VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of December 6, 2013 NEPOOL 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 annual meeting of the NEPOOL Participants Committee will be held on **Friday, December 6, 2013 at 10:00 a.m. at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA.** The meeting will be preceded by a Holiday Breakfast beginning at 9:00 a.m. that we hope you will attend. As previously indicated, FERC Commissioner John Norris is joining us at the beginning of the meeting and we hope you will have a chance over breakfast to interact with him informally. The Participants Committee meeting will be held in the Huntington Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at [http://www.nepool.com/NPC2013.php](http://www.nepool.com/NPC2013.php). For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

Do you want to change your Sector? If so, that can only happen at NEPOOL’s next Annual Meeting, which is this December 6 meeting. To change Sectors for next year, you must provide us with written notice of that request prior to the December 6 meeting. Under Section 6.3 of the current NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first Annual Meeting following that request.

Directions to the Colonnade Hotel are included with this notice. Please note that the discounted block of rooms for this meeting is full and the hotel is sold out. You may be able to be put on a wait list at the Colonnade if there are any cancellations by calling the hotel directly (617-385-4514) and reference the “NEPOOL Participants Committee” block of rooms. Should you have difficulty finding rooms for the December 6 meeting, please contact Cindy Jacobs, NEPOOL Administrator ([ckjacobs@daypitney.com](mailto:ckjacobs@daypitney.com) / 860-275-0246) and she will try to assist you.

Respectfully yours,

/s/ David T. Doot, Secretary
1. To approve the preliminary minutes of the November 8, 2013 meeting. Draft minutes of the November 8 meeting are included for the first time with this supplemental notice and posted on the NEPOOL website. To the extent you have any comments on the minutes, please provide those no later than noon on Wednesday, December 4. We will circulate revised minutes as appropriate on December 4, with the Committee voting to approve only if members are prepared to do so on December 6.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice.

2A. To consider, and take action, as appropriate, on proposed revisions to ISO OP 12 (Voltage and Reactive Control) and Appendices B-D, as recommended by the Reliability Committee. Background materials and a draft resolution are posted with this supplemental notice.

3. To receive comments from The Honorable John Norris, Commissioner of the Federal Energy Regulatory Commission.

4. To receive an ISO Chief Executive Officer Report.

5. To receive an ISO Chief Operating Officer Report.

6. To receive the 2013 NEPOOL Annual Report, which will be distributed in printed form at the Participants Committee meeting and posted on the NEPOOL website.

7. To elect NEPOOL Participants Committee Officers for 2014. A draft resolution reflecting the outcome of earlier balloting for the Participants Committee Chair is posted with this supplemental notice.

8. To adopt a NEPOOL Budget for 2014. Background materials and a draft resolution are posted with this supplemental notice.

9. To consider, and take action, as appropriate, on proposed revisions to Market Rule 1 Appendix A regarding Offer Review Trigger Prices (ORTP) for FCA9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation. Background materials and a draft resolution are posted with this supplemental notice.

10. To consider and take action, as appropriate, on the following:

   a. Proposed revisions to Market Rule 1, Market Rule 1 Appendix A, and Tariff Section I.2.2 to implement the FCM Performance Incentives Proposal and mitigation design.

   b. Proposed revisions to ISO-NE Financial Assurance Policy to reflect the changes described above relating to the FCM Performance Incentives Proposal and mitigation design.

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

10A. To consider and take action, as appropriate, on the November 25 “Exigent Circumstances” filing by ISO-NE. A copy of that ISO-NE filing and background materials that include a draft resolution are posted with this supplemental notice.

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

12. To receive reports from committees and subcommittees.

13. To transact such other business as may properly come before the meeting.
A meeting of the NEPOOL Participants Committee, preceded by Sector meetings with the ISO Board and New England state regulators, was held beginning at 1:30 p.m. on Friday, November 8, 2013 at the Hilton Logan Airport Hotel, Boston, MA pursuant to notice duly given. 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 attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present, including the ISO Board members and many other state representatives in attendance following their participation in the Sector discussions earlier in the day.

APPROVAL OF OCTOBER 4, 2013 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the October 4, 2013 meeting as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes for the October 4 meeting were unanimously approved.

CONSENT AGENDA

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved with oppositions by: CSC, ConEd, and LIPA. Each of the representatives who opposed attributed their positions to Consent Agenda Items #3 and #4, which related to HQICC, ICR, and associated Values for the upcoming reconfiguration auctions. They
explained that their opposition was based on their continued and previously explained position that the values do not recognize the reliability benefits of the Cross-Sound Cable.

OTHER BUSINESS – PROCESS TO ADDRESS NEPGA COMPLAINT

Prior to the ISO Chief Executive Officer Report, Mr. Doot reviewed for the Committee the ISO’s memorandum circulated and posted in advance of the meeting concerning a complaint filed on October 31 by the New England Power Generators Association (NEPGA) against the ISO alleging that the administrative prices set under the rules for Inadequate Supply and Insufficient Competition and the Carry Forward rules were discriminatory and unjust and unreasonable (Complaint). He said that the ISO was required to file its answer to the Complaint by November 20 unless the answer date was extended by the FERC. As set forth in the ISO’s memorandum, with non-price retirement requests for 3,135 MW of resources having been submitted or approved, the situation in the New England capacity market has changed significantly since the stakeholder process last considered, and failed to support, changes to these rules, as proposed by Exelon. Accordingly, he said that the ISO believed that an expedited stakeholder process would be valuable to further inform its answer and to assure that all NEPOOL Participants and state regulators have an opportunity to discuss the issues collectively. He stated that the ISO intended to post a memorandum on November 9 that would encompass the ISO’s thinking with regard to the complaint. The ISO was planning to discuss these issues at the November 13 Markets Committee meeting, with an additional Markets Committee meeting tentatively scheduled for November 18. Following the November 18 meeting, a tentative Special Participants Committee meeting would be scheduled on November 22 in order to permit a Participants Committee vote on matters
surrounding the Complaint, if desired, and to give FERC sufficient time to issue a decision prior to the eighth Forward Capacity Auction (FCA8). If that process was agreeable, the ISO indicated it would seek a brief extension of time for the filing of its answer.

**REPORT OF THE ISO CHIEF EXECUTIVE OFFICER**

Mr. van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the October 4 meeting, circulated in advance of the meeting. There were no questions or comments on the ISO Board and Board Committee meetings report.

**REPORT OF THE ISO CHIEF OPERATING OFFICER**

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the November COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing specifically on report highlights, he stated that in October: (i) natural gas prices were 1.7% higher and oil prices were 1.2% lower than September 2013 average values; (ii) Real-Time Hub locational marginal prices (LMPs) were down 1.1% from September 2013 averages; (iii) Net Commitment Period Compensation (NCPC), totaling $2.4 million, was $2.3 million lower than September 2013 NCPC; (iv) first contingency payments, totaling $1.7 million, were $504,000 higher than September’s first contingency payments; (v) second contingency payments totaled $441,000, which was lower than the $3.2 million in September; and (vi) voltage support payments totaled $173,000, up $92,000 from September. He reported that, based on the 50/50 and 90/10 load forecasts, the lowest Fall Operable Capacity Margin was projected for the week beginning November 16.
and the lowest Winter Operable Capacity Margin was projected for the week beginning January 18, 2014.

Dr. Chadalavada reported that the 2013 Regional System Plan (RSP 13) was sent to the ISO Board and approved by the Board on November 7. He stated the work was a continuous process and that the team at the ISO and the Planning Advisory Committee (PAC) were already working on the next version (RSP 14). He reported that there were two FCA8-related FERC filings made on November 5, one indicating the resources qualified to participate in the auction and the other, the Installed Capacity Requirement, Local Sourcing Requirement, and Maximum Capacity Limit for the 2017/2018 Capability Year. He stated that a compliance filing in response to Order 1000 was scheduled to be filed on November 15 and would be discussed later in the meeting.

Regarding the Forward Capacity Market, he reported that the non-price retirement (NPR) requests for Vermont Yankee had been approved and other NPR requests were under study, with results to be presented at the December Reliability Committee meeting. He stated FCA8 would commence on February 3, 2014. For subsequent auctions, beyond FCA8, capacity zones could change, as was then being discussed with NEPOOL. Dr. Chadalavada explained, in response to questions, that the ISO planned to review with the Markets Committee the following week its plans for FCA8 settlement in light of planned retirements and information that it planned to release, as noted earlier in the meeting, on November 9.

On Winter Operations for 2013/2014, Dr. Chadalavada reported on long-term weather predictions for the winter. He reviewed that the winter peak load 50/50 forecast is 21,299 MW, with the Lowest Winter Operable Capacity projected for the week of January 18. During that week, Capacity Supply Obligations (CSOs) only exceeded projected load by 525
MW. When looking at the 90/10 forecast of 21,934 MW though, the ISO projected a
deficiency of 1143 MW, principally because under 90/10 conditions the ISO expected extreme
weather, with increased constraint on the natural gas pipeline system and gas unit outages.

Referring to slides reflecting the ISO’s preparedness for the 2013/2014 Winter period,
Dr. Chadalavada reviewed the ISO’s assumptions that natural gas pipelines would be largely
available, but at capacity. He reported that the ISO was expecting: 150,000 MMbTUs/day at
Deep Panuke (making note of gas quality issues being experienced as release rates were being
increased as Deep Panuke reached full commercial); 150,000 MMbTUs/day at Sable Island
(an increase of 25,000 MMbTUs/day from the prior winter); and fewer cargoes than in past
winters at two LNG terminals.

He updated the Committee on the Winter 2013/2014 Reliability Program, stating that 3
out of 14 units participating in the dual fuel aspect of the Program had successfully tested
their switching capability and the three demand resource assets to be active during the
Program have also declared their readiness for participation. He stated his expectation that
the remaining assets would finish the readiness process by December 1.

Dr. Chadalavada concluded by referring the Committee to a chart reflecting the impact
of the Replacement Reserve Product, which had an associated trigger price of $250 and went
into effect on October 1. Based on the first month of data, the changes appeared to be
working as intended. The ISO had increased reserves committed Day-Ahead, thru the
Reserve Adequacy Analysis (RAA) and into Real-Time, and to the extent those were
insufficient replacement reserves, the associated Reserve Constraint Penalty Factor (RCPF)
was triggered.
Members asked clarifying questions and provided comments. Some questioned whether the new replacement reserve was good for consumers, as they were resulting in high price spikes. Dr. Chadalavada responded that the change helped to ensure that costs to supply are reflected in Real-Time prices rather than through uplift. Loads should be able to use the Day-Ahead Market as a way to hedge against the impacts of replacement reserves. He stated the ISO would review the market results for the next several months before drawing any final conclusions.

A member asked what the out-of-market costs were for the three units that were tested in the 2013/14 Winter Reliability Program. Dr. Chadalavada responded that the costs were approximately $190,000.

2013 THIRD QUARTER MARKETS REPORT

MR. DAVID LAPLANTE, ISO VICE PRESIDENT AND INTERNAL MARKET MONITOR (IMM), REVIEWED THE 2013 THIRD QUARTER MARKETS REPORT AND REVIEW OF FCA8 DE-LIST BIDS PRESENTATION POSTED IN ADVANCE OF THE MEETING. HE BEGAN WITH A SUMMARY OF THE DE-LIST BID PROCESS, NOTING TWO KEY CHANGES FOR FCA8 THAT LED TO A SIGNIFICANT INCREASE IN THE AMOUNT OF DE-LIST BIDS SUBMITTED: (1) THE REMOVAL OF THE FLOOR PRICE AND (2) THE OPTIONALITY ON STATIC DE-LIST BIDS. HE REPORTED THAT THE ISO DID SEE MANY MORE DE-LIST BIDS FOR FCA8, GIVEN STATIC DE-LIST BIDS COULD BE REDUCED OR REVOKED ENTIRELY, AND WERE NO LONGER BINDING. HE STATED THE IMM'S RESPONSIBILITY WAS TO MAKE SURE THAT A PARTICIPANT'S DE-

HE REVIEWED THE FIVE PARTICIPANT OPTIONS AFTER RECEIVING THE QDN:

1. CHALLENGE THE IMM-DETERMINED DE-LIST BID AT THE FERC.
2. ACCEPT THE IMM-DETERMINED/ACCEPTED DE-LIST BID.
3. REDUCE THE DE-LIST BID.
4. WITHDRAW THE DE-LIST BID.
5. SUBMIT A NON-PRICE RETIREMENT REQUEST.

MR. LAPLANTE SUMMARIZED AS FOLLOWS:

- 79 DE-LIST BIDS WERE SUBMITTED;
- 73 STATIC DE-LIST BIDS REQUIRED IMM COST REVIEW;
- 44 OF THE 73 DE-LIST BIDS WERE ACCEPTED; AND
- 29 OF THE DE-LIST BIDS WERE DENIED, DUE TO THE IMM’S DETERMINATION THAT THE DE-LIST BID WAS INCOMPLETE OR INCONSISTENT WITH THE RESOURCE’S GOING FORWARD COST.

IN RESPONSE TO A MEMBER REQUEST FOR A BREAKDOWN OF THE 44 ACCEPTED DE-LIST BIDS, MR. LAPLANTE REPORTED THAT 38 WERE DEMAND RESPONSE BIDS AND 6 WERE GENERATOR BIDS. HE REPORTED THAT OF THE 29 BIDS DENIED, MOST WERE GENERATORS.
HE IDENTIFIED THE FOLLOWING REASONS FOR DENIAL OF THE DE-LIST BIDS:

- INCOMPLETE DATA OR DATA ERRORS;
- INSUFFICIENT EXPLANATION OF ESTIMATES OR ASSUMPTIONS; AND
- SUBMITTAL OF NEW INFORMATION DURING CONSULTATION PROCESS REDUCING ORIGINALLY SUBMITTED DE-LIST BIDS.

HE EXPLAINED THAT UNITS OVERESTIMATED THEIR PROBABILITY OF EXPERIENCING A LONG-TERM OUTAGE OR DE-RATE RestrictING THE UNIT FROM OPERATING UP TO ITS CSO. HE STATED THE IMM USED HISTORICAL DETERMINATIONS OF SIGNIFICANT DECREASES IN CAPACITY AS OBSERVED FOR THE FINAL ANNUAL CONFIGURATION AUCTIONS HELD TO DATE FOR NON-INTERMITTENT GENERATING RESOURCES. IN THOSE AUCTIONS, ONLY 5.5% OF THE GENERATORS EXPERIENCED A SIGNIFICANT DECREASE IN CAPACITY DETERMINATIONS. ACCORDINGLY, THE IMM SUBSTITUTED 5.5% IN ITS DETERMINATION OF DE-LIST BIDS FOR GENERATORS, WHICH REFLECTED THE LARGEST CHANGE IN THE DE-LIST PROCESS.

TURNING TO THE 3RD QUARTER MARKETS REPORT, MR. LAPLANTE HIGHLIGHTED AN EVENT ON SEPTEMBER 11 WHEN THERE WAS PRICE SEPARATION IN THE DAY-AHEAD MARKET BETWEEN THE HUB AND LOAD-ZONE LMPS AND THERE WERE SIGNIFICANT PRICE DEVIATIONS BETWEEN THE DAY-AHEAD MARKET AND REAL-TIME LMPS. THE IMM CONCLUDED THAT OUTCOME WAS THE RESULT OF TRANSMISSION LINE OUTAGES
THAT AFFECTED DAY-AHEAD MARKET PRICING, LOADS RUNNING OVER FORECAST, AND THE RESERVE RESTRAINT PENALTY FACTORS BINDING DURING THE HOURS OF HIGH REAL-TIME PRICES. IN RESPONSE TO A MEMBER QUESTION AS TO WHETHER OR NOT THE IMM CHECKED INTERCONTINENTALEXCHANGE (ICE) OR SOME OF THE OTHER FINANCIAL PLATFORMS TO IDENTIFY POSSIBLE MANIPULATION, MR. LAPLANTE STATED THAT, GIVEN THE LIMITED LEVEL OF DETAIL AND ACCESS TO THOSE PLATFORMS TO WHICH THE ISO WAS PRIVY, THE IMM DID NOT LOOK AT THE FORWARD MARKET OUTCOMES OR THE ICE MARKET OUTCOMES.

A MEMBER EXPRESSED CONCERN THAT 1,900 MW OF DE-LIST BIDS SUBMITTED NON-PRICE RETIREMENTS, DRIVING THE POOL SHORT, AND QUESTIONED WHY THERE WAS SUCH A DIFFERENCE IN OPINION BETWEEN THE IMM AND THE GENERATORS AS TO APPROPRIATE DE-LIST BIDS. MR. LAPLANTE ARTICULATED HIS VIEW THAT THE TARIFF COULD BE IMPROVED AND THAT THE IMM COULD CONSIDER ALLOWING GREATER FLEXIBILITY UNDER AN FCM WITH APPROPRIATE PERFORMANCE INCENTIVES, BUT THE DECISION TO RETIRE A UNIT HAD TO BE BASED ON THE LONG-RUN LOOK AT THAT UNITS VIABILITY AND NOT ATTRIBUTED TO THE IMM DETERMINED DE-LIST BID VALUES BEING TOO LOW.
NCPC PAYMENT REDESIGN PROPOSAL

MS. ALLISON DIGRANDE, CHAIR, MARKETS COMMITTEE, REFERRED THE COMMITTEE TO THE MATERIALS POSTED IN ADVANCE OF THE MEETING REGARDING REVISIONS TO MARKET RULE 1, INCLUDING APPENDICES A AND F, AND TARIFF SECTION I.2.2 RELATED TO NCPC PAYMENT AND MITIGATION (THE NCPC PROPOSAL). SHE EXPLAINED THAT THE MARKETS COMMITTEE UNANIMOUSLY APPROVED A RESOLUTION TO RECOMMEND PARTICIPANTS COMMITTEE SUPPORT FOR AN EARLIER VERSION OF THE ISO’S NCPC PROPOSAL, BUT SINCE THAT VOTE, THE ISO CONSIDERED FURTHER THE FEEDBACK IT RECEIVED FROM THE MARKETS COMMITTEE AND IDENTIFIED ADDITIONAL CHANGES. SHE REVIEWED THE ADDITIONAL CHANGES.


WITHOUT FURTHER DISCUSSION, THE FOLLOWING MOTION WAS DULY MADE AND SECONDED:

RESOLVED, THAT THE PARTICIPANTS COMMITTEE SUPPORTS THE REVISIONS TO APPENDICES A AND F TO MARKET RULE 1 AND TARIFF SECTION I.2.2 TO IMPLEMENT THE NCPC PAYMENT REDESIGN AND NCPC MITIGATION DESIGN AS RECOMMENDED BY THE MARKETS COMMITTEE AT ITS OCTOBER 8-9, 2013 MEETING, AND AS PROVIDED TO THIS COMMITTEE IN
ADVANCE OF THIS MEETING, TOGETHER WITH THOSE 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 MARKETS COMMITTEE.

THE COMMITTEE VOTED AND UNANIMOUSLY APPROVED THE MOTION WITH ABSTENTIONS NOTED BY: BP, CSC, CALPINE, CONED, DOMINION, DYNEGY, ENERGY AMERICA, ENTERGY, ENVIRONMENT NORTHEAST, EQUIPOWER, ESSENTIAL POWER, GALT POWER, GRANITE RIDGE, HESS, HQ, INTEGRYS, LIPA, LITTLETON (NH), NEXTERA, NRG, PSEG, VEC, AND VITOL.

FCM NON-COMMERCIAL CAPACITY CHANGES TO FINANCIAL ASSURANCE POLICY

Mr. Joel Gordon, Chair, Budget & Finance Subcommittee (Subcommittee), referred the Committee to the materials posted in advance of the meeting concerning changes to the ISO Financial Assurance Policy (FAP) in connection with the financial assurance requirements for Non-Commercial Capacity participating in the FCM. He explained that Section III.13.1.9 of the FCM Rules required the ISO and Subcommittee to reconsider the financial assurance requirements for the FCM no later than five years after the first Forward Capacity Auction was conducted. He stated that Section VII of the FAP required the ISO to reconsider no later than June 2015 the $5.737 kW-month value used for the calculation of financial assurance amounts related to the FCM. He reported that there was general consensus on the proposal at the last Subcommittee meeting, with a proposed amendment identified that would be offered at this meeting.

The following motion was duly made and seconded:
RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO New England Financial Assurance Policy related to the financial assurance requirements for Non-Commercial Capacity in the Forward Capacity Market, as circulated to the Committee and discussed at this meeting, together with such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve.

The Vermont Energy Investment Corporation (VEIC) representative offered a motion to amend the main motion, which was duly made and seconded, so as to relieve state-funded energy efficiency programs from providing additional Non-Commercial Capacity Financial Assurance when its Non-Commercial Capacity fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation.

The Committee commented and asked clarifying questions on the VEIC Amendment. The representatives of AIM, CT OCC, NH OCA, and TEC expressed support for the amendment. In response to a member’s request for clarification as to the basis for distinguishing (lowering) the amount of financial assurance to be provided by state-funded energy efficiency programs as compared to the financial assurance that any other Participant would need to post, the VEIC representative responded that such treatment was consistent with the expressed intent of the ISO. The proposed changes were to ensure resources had sufficient economic incentive to force a decision as to whether to continue developing their
Mr. Marc Montalvo stated the ISO did not support the VEIC Amendment. He stated that, once a commitment period begins, all cleared resources are obliged to deliver, and a resource that is late has failed to meet its market obligation. The ISO sought added assurance from the Market Participant with the obligation that it would continue to work diligently to complete its project and did not see for these purposes any material difference between an energy efficiency project and other types of projects.

Following final comments by VEIC, the Committee voted and failed to approve the motion to amend the main motion with a 59.34% Vote in favor (Generation – 6.44%; Transmission – 5.72%; Supplier – 0%; Alternative Resources – 14.17%; Publicly Owned Entity – 17.17%; and End User – 15.84%). (See Vote 1 on Attachment 2).

The Committee then voted and unanimously approved the unamended main motion.

**ORDER 1000 MAY 17 COMPLIANCE ORDER CHANGES**

Mr. Donald Gates, Chair, Transmission Committee, referred the Committee to the materials posted in advance of the meeting regarding Order 1000 May 17 Compliance Order changes. He reported that the Transmission Committee acted on the compliance changes at its October 30, 2013 meeting in two separate actions, one on the Planning Revisions and one on the Cost Allocation Revisions. Mr. Bowie indicated that the Participants Committee
would also proceed with two separate actions. He noted that New Hampshire Transmission (NHT) had a friendly amendment it was proposing to the Planning Revisions recommended by the Transmission Committee.

The representative of NHT explained the changes sought through the friendly amendment, which were to remove revisions made to Sections 4.3(b) and 4A.5 of Attachment K and restore the ISO’s earlier language. There were no objections and the friendly amendment was adopted as part of the main motion. The NHT representative then explained the two categories of changes to the ISO’s earlier proposal: (1) to remove Proposed Projects from grandfathering because these projects are still in the process of evaluation and are not even at the point where they could be could be re-evaluated; and (2) to ensure a fair and inclusive competitive process by making sure all Qualified Transmission Project Sponsors have access to the same information and to the ISO at the same time with regards to Needs Assessments.

The following motion was duly made and seconded:

RESOLVED, that the Participants Committee supports the recommendation of the Transmission Committee regarding the Planning Revisions to revise the TOA and Sections I and II of the ISO Tariff in response to Order No. 1000 and the May 17 Compliance Order as reflected in the materials distributed to the Participants Committee for its November 8, 2013 meeting, together with those 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; and further resolved that the Participants Committee authorizes NEPOOL counsel to reflect that recommendation in NEPOOL’s submission to the FERC of comments and other pleadings as appropriate in the Order No. 1000 proceeding.

The Committee then commented on the Proposal that was the subject of the main motion. Transmission Owner representatives stated objections to the Proposal because it
would limit grandfathering in a way they viewed as inefficient, exposing projects that had already been extensively studied to the competitive process. A Massachusetts Department of Public Utilities (MA DPU) representative objected to not grandfathering the Greater Boston Projects, but would support the requirement to involve all Qualified Transmission Project Sponsors in Needs Assessment studies. The Connecticut Department of Energy & Environmental Protection (CT DEEP) representative stated opposition to the Proposal because of its failure to grandfather Proposed Projects. A NESCOE representative expressed appreciation to the ISO and the PTOs for their compliance work, noting NESCOE’s rehearing request, and stating that NESCOE did not have a position on the Planning Revisions because of division among its members.

The ISO referred the Committee to its memorandum expressing its opposition to the Proposal, posted in advance of the meeting.

The once-amended main motion (as amended by the NHT Friendly Amendment) was then voted and determined to have passed by a show of hands, with oppositions noted by: Bangor, CT OCC, CMP, National Grid, NU, UI, and VELCO; and abstentions noted by: EnerNOC, Essential Power, IECG, Linde, Kimberly-Clark, LIPA, Praxair, PSEG, AR LR Provisional Group Member, and VEIC.

At the request of the ISO, the Committee considered and failed to approve the ISO’s unamended Planning Revisions and TOA Revisions (the ISO Proposal). The ISO Proposal was determined to have failed by a show of hands, with support in favor noted by: Bangor, CMP, CT OCC, First Wind, National Grid, NU, UI, and VELCO; and abstentions noted by: CLF, EnerNOC, Essential Power, HQ, and LIPA.

Cost Allocation Revisions
Mr. Gates then introduced the Cost Allocation Revisions and indicated that MMWEC would be proposing an amendment.

The following motion as duly made and seconded:

RESOLVED, that the Participants Committee supports the recommendation of the Transmission Committee regarding the Cost Allocation Revisions to revise the definition of Localized Costs of Section I of the ISO Tariff, and Schedules 12 and 12C and Attachment K of Section II of the ISO Tariff in response to Order No. 1000 and the May 17 Compliance Order as reflected in the materials distributed to the Participants Committee for its November 8, 2013 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee; and further resolved that the Participants Committee authorizes NEPOOL counsel to reflect that recommendation in NEPOOL’s submission to the FERC of comments and other pleadings as appropriate in the Order No. 1000 proceeding.

The Committee commented on the cost allocation revisions. Opposition was expressed by some who viewed 70% regionalization of costs as too high. It was confirmed that the cost allocation was only to be a default mechanism. State representatives present were divided on the proposal, with representatives of MA and CT supporting, and NH and RI opposing. NESCOE, accordingly, explained that it did not have a position on the cost allocation proposal, but supported its role in identifying public policy requirements that drive transmission needs. Others expressed support for the proposal as a reasonable compromise between those seeking full regionalization and those seeking localization.

The MMWEC representative presented a motion to amend the main motion (the MMWEC Amendment) so as to have no more than 30% of costs regionalized and projects reviewed on a case-by-case basis; the proposal also would exempt entities that are not subject to public policy requirements from the costs of public policy transmission projects. The
MMWEC representative offered the following motion to amend the main motion, which was seconded:

To revise the proposed Schedule 12C and Localized Costs definition, including a statutory exemption for municipal load without a renewable portfolio standard requirement and a 30/70 cost allocation (with a maximum 30% regionalized, the remainder subject to allocation to the identified beneficiary), as proposed by MMWEC in materials circulated in advance of the meeting.

The Committee then commented on the MMWEC Amendment. Some support was expressed for shifting more costs towards identified beneficiaries. The New Hampshire Public Utilities Commission (NHPUC) representative stated that it had worked closely with MMWEC in developing the amendment, supported it, and clarified that the proposed exemption would only apply to Renewable Portfolio Standards requirements.

The ISO representative stated an ISO concern that it would be difficult to implement the MMWEC proposal.

Following concluding remarks by MMWEC, the Committee voted and failed to approve the MMWEC motion to amend the main motion with a 52.81% Vote in favor (Generation – 14.71%; Transmission – 2.86%; Supplier – 12.26%; Alternative Resources – 0.08%; Publicly Owned Entity – 17.17%; and End User – 5.72%). (See Vote 2 on Attachment 2).

The Committee then considered the unamended main motion, which was voted and failed with a 51.57% Vote in favor (Generation – 0%; Transmission – 14.31%; Supplier – 8.58%; Alternative Resources – 14.17%; Publicly Owned Entity – 0.46%; and End User – 14.05%). (See Vote 3 on Attachment 2).
LITIGATION REPORT

Mr. Patrick Gerity referred the Committee to the November 6 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted that responses and comments on the NEPGA Complaint would, absent any extension requested of and granted by the FERC, be due November 20. He urged members to let NEPOOL Counsel know, either directly or through their Sector Officers, their thoughts on where NEPOOL ought to be in response to the Complaint. He highlighted that comments on the FCA8 qualification informational filing were also due November 20 and noted that the 2014 ISO and NESCOE budget filings were pending before the FERC. Mr. Gerity further highlighted two FERC orders summarized in the Report: one that accepted the shortage event triggers filing with the ISO-proposed November 3, 2013 effective date; the other, the order that conditionally accepted the energy market offer flexibility changes, subject to a compliance filing which, pursuant to a joint NEPOOL/ISO request for an extension of time to permit to permit December Markets Committee and January Participants Committee consideration, would be due January 17, 2014. Of final note, the FERC had issued the evening before the meeting an order accepting the ISO’s cost recovery Market Rule compliance filing submitted in response to FERC directives in the Section 206 proceeding initiated following Dominion’s earlier cost recovery filing. In accepting the compliance filing, the FERC rejected requests for the opportunity for broader recovery in extraordinary circumstances. Mr. Gerity encouraged anyone with comments or questions on the Report to please contact him or any of NEPOOL’s counsel.
OTHER BUSINESS

Mr. Gerity referred the Committee to the NEPOOL calendar for December, highlighting upcoming meetings and events through the end of 2013. He reported that the next regularly-scheduled meeting of the Participants Committee, the 2013 Annual Meeting, would be December 6 at the Colonnade Hotel in Boston. He noted that FERC Commissioner, the Honorable John Norris planned to attend that meeting. Mr. Gerity highlighted the Consumer Liaison Group meeting scheduled for December 5, also at the Colonnade Hotel, and noted several industry meetings and holiday parties during that time period. He directed the Committee to balloting for the 2014 Chairman, which was in progress, and asked that all first round ballots be returned by November 15.

DISCUSSION OF ISO PROCESS ON SUBSTANTIVE COMMENTS OF NEPGA COMPLAINT

Following clarifying questions from the Committee, the ISO stated the purpose of the discussion at that meeting was to discuss process and whether stakeholders wanted substantive discussion. The Officers determined ahead of the meeting that the desired process really depended on the substance of ISO’s input. Therefore the ISO indicated it would issue and post a memorandum the following day, November 9, that would address the ISO’s issues substantively, and would use the November 13 Markets Committee meeting to discuss the issues further. The ISO stated that the memorandum would describe the problems the ISO saw, but would not contain a proposed solution. The ISO sought feedback on the stakeholder process.

There being no further business, the meeting adjourned at 4:00 p.m.

Respectfully submitted,
David T. Doot, Secretary
## MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 8, 2013 PARTICIPANTS COMMITTEE MEETING

<table>
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<tr>
<th>PARTICIPANT NAME</th>
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# NEPOOL PARTICIPANTS COMMITTEE
## DEC 6, 2013 MEETING, AGENDA ITEM #1
### ATTACHMENT 1

## MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 8, 2013 PARTICIPANTS COMMITTEE MEETING

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### VOTES TAKEN AT

**NOVEMBER 8, 2013 PARTICIPANTS COMMITTEE MEETING**

#### TOTAL

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**ATTACHMENT 2**
## VOTES TAKEN AT
### NOVEMBER 8, 2013 PARTICIPANTS COMMITTEE MEETING

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From the notice of actions of the November 13-14, 2013 Markets Committee\(^1\) meeting, dated November 15, 2013, which has been previously circulated:

1. **Revisions to Market Rule 1 Appendix F (NCPC Local Second Contingency Protection Resource Cost Allocation)**

   Support revisions to Market Rule 1 Appendix F that modify the cost allocation for Day-Ahead Energy Market Local Second Contingency Protection Resource requirements, as recommended by the Markets Committee at its November 13-14, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved with a 80.61% Vote in favor (Generation - 8.58%; Transmission - 17.17%; Supplier - 6.36%; AR - 14.17%; Publicly Owned Entity - 17.17%; and End User - 17.17%).

2. **Move Fuel Switching Provision (Use of Reference Level as the Supply Offer) From Appendix K to Market Rule 1 to Section III.1.11.3**

   Support the move of the provisions that permit the use a dual-fuel resource’s secondary fuel reference level as its supply offer following a fuel switch, from Appendix K to Market Rule 1 to Section III.1.11.3 of Market Rule 1 (extending its effectiveness beyond the scheduled expiration of Appendix K), as recommended by the Markets Committee at its November 13-14, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously with seven abstentions noted (6 Supplier Sector and 1 Alternative Resources Sector).

3. **Revisions to Market Rule 1 Appendix E1 (Demand Response Baseline and Outages)**

   Support revisions to Market Rule 1 Appendix E1 to implement the Demand Resources Working Group-recommended changes to the Demand Response baseline to account for scheduled and forced curtailments of demand response assets, as recommended by the Markets Committee at its November 13-14, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously with two abstentions in the Generation Sector noted.

MEMORANDUM

TO: NEPOOL Participants Committee
FROM: Eric Runge, NEPOOL Counsel
DATE: November 27, 2013
RE: Operating Procedure 12 (OP-12) Revisions

At the December 6, 2013 Annual Meeting, you will be asked to vote on minor revisions to OP-12 and related appendices. OP-12 provides details regarding voltage and reactive control service. The revisions are designed to provide more clarity on establishing and maintaining voltage schedules, criteria for allowable deviation from schedules, separation of the system voltage survey as a stand-alone document, and creation of a standard form used to notify Market Participants of their schedule. These revisions were supported without opposition or abstention at the November 19, 2013 Reliability Committee meeting, and would have been on the Annual Meeting’s Consent Agenda but for the timing of the vote and notice of actions, which did not allow sufficient time to meet the notice requirements for Consent Agenda consideration.

The following resolution is provided for your use at the Participants Committee meeting:

RESOLVED, that the Participants Committee supports the proposed revisions to OP-12 as recommended by the Reliability Committee at its November 19, 2013 meeting, together with [such other changes as were agreed to at the meeting, and] such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

1 The mark-up of OP-12 and its appendices that was used for the Reliability Committee vote has been included with this memo.
ISO New England Operating Procedure No. 12
VOLTAGE AND REACTIVE CONTROL

Effective Date: Draft

References:

1. NERC Reliability Standard VAR-001 - Voltage and Reactive Control
2. NERC Reliability Standard IRO-005 - Reliability Coordination Current Day Operations
3. NERC Reliability Standard VAR-002 - Generator Operations for Maintaining Network Voltage Schedules
4. NPCC Directory #10 - Verification of Generator Gross and Net Reactive Power Capability (NPCC D#10)
5. ISO New England Ancillary Service Schedule No. 2 Business Procedure
6. ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)
7. ISO New England Operating Procedure No. 7 - Action in an Emergency (OP-7)
8. ISO New England Operating Procedure No. 14 - Technical Requirements for Generator Demand Resources and Asset Related Demands (OP-14)
11. Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8)
12. Master/Local Control Center Procedure No. 9 - Operation of the Chester Static VAR Compensator (SVC) (M/LCC 9)
13. ISO New England Transmission Operating Guides - All Voltage/Reactive Guides

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Hard Copy Is Uncontrolled

Revision 5, Effective Date: draft

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APPENDICES

Appendix A - Voltage/Reactive Documents in the ISO New England Transmission Operating Guides
Appendix B - Voltage and Reactive Schedules
Appendix C - Voltage & Reactive Surveys
Appendix D - Voltage Schedule Annual Transmittal Form
I. INTRODUCTION

This Operating Procedure (OP) provides broad criteria, operating practices and responsibilities to help ensure that desired/reliable voltage and reactive conditions are maintained on the power system. It also includes general actions to control voltage/reactive conditions when deviations from normal occur or are needed to minimize adverse effects during abnormal conditions.

More specific criteria and actions may be required when the measures described in this OP do not correct the abnormal voltage/reactive conditions. This information is contained in detailed voltage/reactive documents issued as part of the ISO New England (ISO) Transmission Operating Guides. Whereas these guides are referenced several times throughout this OP, Appendix A - Voltage/Reactive Documents in the ISO New England Transmission Operating Guides lists the applicable permanent operating guides and indicates the types of information they contain. To facilitate references to Appendix A, its column numbering and headings are consistent with the format and order of this OP.

However, Appendix A does not list temporary transmission operating guides that can contain additional criteria and actions required to correct abnormal voltage/reactive conditions. These temporary operating guides can be found in the Operations Documents Management System (ODMS).
II. CRITERIA

A. VOLTAGE SCHEDULES AND LIMITS FOR GENERATORS AND KEY TRANSMISSION STATIONS

Voltage schedules and limits for NERC registered and/or transmission (69 kV or higher) connected Generators that can control transmission voltage and key transmission stations are specified by ISO in Appendix B - Voltage & Reactive Schedules (Appendix B) of this OP. Appendix B includes voltage schedules for:

- Generators
- Transmission Static Synchronous Compensators (STATCOMs)
- Autotransformers with Load Tap Changers (LTCs)

Size information is included for:

- Transmission Capacitors
- Transmission Reactors

For the limited number of Generators not listed in Appendix B, their voltage schedules are specified as follows:

- Generators listed in Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8), Attachment A - Generators Exempted from AVR Requirements are Generators that ISO has exempted from the requirement to have an automatic voltage regulator (AVR). As noted in M/LCC 8, Attachment A, these Generators follow a reactive power schedule by operating near unity power factor.

- Generators not listed in OP-12, Appendix B or M/LCC 8, Attachment A will follow local voltage schedules specified by the applicable Local Control Center (LCC) in accordance with LCC requirements or as required in their interconnection agreements.

- Voltage schedules are not specified for Generators not modeled in the ISO Energy Management System (EMS)

The voltage schedule specified for a Generator in OP-12, Appendix B is the prescribed voltage that a Generator must maintain as measured at the high side of the Generator step-up transformer or as otherwise specified. This voltage schedule, which is specified for both heavy and light load periods, is represented by a kV schedule value with accompanying operational kV high and kV low values which establish the “voltage schedule tolerance band”. A Generator shall maintain voltage output within its voltage schedule tolerance band values in system operations at all times while one or more units at the generating station is online, unless otherwise directed by ISO or the LCC. These voltage schedules shall also be used by operators and planners in off-line studies of the power system.

During certain infrequent, atypical conditions at a generating station or on the power system, ISO or an LCC may instruct a Generator to deviate from its voltage schedule.
ISO New England Operating Procedure OP-12 - Voltage and Reactive Control

and to operate at a voltage output level outside of the voltage schedule tolerance band but within the wider minimum and maximum "acceptable" voltage schedule range, which is also listed in OP-12, Appendix B. These minimum and maximum "acceptable" voltage schedule range values are based on data provided by the Generators on Form NX-12D in accordance with ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands (OP-14).

Voltage schedules and acceptable voltage ranges are referenced, and in some cases further detailed, in the area voltage guides issued as part of the ISO Transmission Operating Guides (refer to Appendix A, column 1).

B. GENERATOR REACTIVE CAPABILITIES, COMMITMENTS AND REQUIRED REACTIVE RESERVES

Generator reactive capabilities available to regulate voltages shall be employed in system operations and analyses. Data collection methods (see OP-14) have been designed such that these reactive capabilities shall be fully available except for occasional times when unique temporary problems occur at a particular generating station.

To promote security of the transmission system during adverse voltage/reactive conditions, required Generator commitments and levels of required reactive reserve from Generators within certain areas of the New England Reliability Coordinator Area (RCA) have been established. System conditions that warrant the prescribed Generator commitments or reactive reserves have also been identified. Details are provided in the ISO Transmission Operating Guides (see Appendix A columns 2 and 3).

C. VERIFICATION OF GENERATOR REACTIVE POWER CAPABILITY

NPCC Directory #10 - Verification of Generator Gross and Net Reactive Power Capability (NPCC D#10) requires that each Transmission Operator establish and administer a Generator Reactive Power Capability Verification Program. It also requires each associated Generator Owner to comply with the Generator Reactive Power Capability Verification Program. The following language establishes the requirements of the ISO-NE Generator Reactive Power Capability Verification Program that each associated Generator Owner must meet to satisfy the NPCC D#10 Generator Owner compliance obligations.

ISO-NE Generator Reactive Power Capability Verification Program applies to Generators that satisfy all of the following conditions:

1. Located in the New England RCA

2. Connected at or above 100 kV and having a MVA capability greater than either one of the following:
   - 20 MVA for a single Generator
   - 75 MVA for a generating station connected at a common transmission bus.

3. Have been identified as having compliance obligations with the NERC Reliability Standards in accordance with the NERC Statement of Compliance Registry.
4. Have not been exempted, by M/LCC 8, from the requirement to have an Automatic Voltage Regulator (AVR) in automatic and controlling voltage

Each Generator Owner shall verify the Reactive Power Capability of their Generators that meet the above criterion in accordance with the requirements and processes contained within Sections 2.2.5 & 2.2.6 of ISO New England Ancillary Service Schedule No. 2 Business Procedure. The ISO New England Ancillary Service Schedule No. 2 Business Procedure can be located on the ISO-NE website.

The one exception to a Generator Owner adherence to the Sections 2.2.5 & 2.2.6 requirements is that the requirement for a Generator to first be recognized as a “Qualified Reactive Resource” does not apply. While Generators that are not recognized as a “Qualified Reactive Resource” do not receive Capacity Cost (CC) compensation under Ancillary Service Schedule 2 - Reactive Supply and Voltage Control from Qualified Reactive Resources Service (“Schedule 2”) under Section II of the ISO New England Tariff, they must still adhere to the Section 2.2.5 & 2.2.6 requirements.

If the results of a reactive capability test demonstrate that a Generator reactive capability is different than the reactive capability reported in the latest NX-12D, the Generator Owner must resolve the discrepancy in accordance with Section 3.9 of Part I and Schedules 22 or 23 of Part II of the ISO Tariff.

To maintain compliance with NPCC D#10 and this OP, a Generator that is unable to conduct the required reactive capability test within the defined period, because of an extended outage, must test within thirty (30) days after returning to service. If the return to service is outside of the defined testing period, or there are not thirty (30) days left in the testing period, the Generator must test within the first thirty (30) days of the next applicable testing period. This does not apply to testing requirements for compensation purposes outlined in the ISO New England Ancillary Service Schedule No. 2 Business Procedure.
III. VOLTAGE/REACTIVE OPERATING PRACTICES

A. TRADITIONAL VOLTAGE/REACTIVE CONTROL

Besides the use of Generator reactive capabilities, the proper dispatch of shunt capacitors/reactors combined with effective transformer voltage schedules or fixed tap settings are the most traditional means of achieving desired voltages and reactive conditions. Listings of switchable shunt devices installed to support the New England Transmission System (115 kV and above) and guides for switching them can be found in OP-12, Appendix B and in the ISO Transmission Operating Guides (see Appendix A, column 4).

B. TRANSMISSION INTERFACE TRANSFER LIMITS TO AVOID LOW VOLTAGE

In some cases, custom software tools have been developed to calculate voltage based transfer limits for transmission interfaces. These limits ensure acceptable voltage response to contingencies. Appendix A column 5 notes the ISO Transmission Operating Guides that contain voltage based transfer limits for transmission interfaces.

C. CIRCUIT SWITCHING TO CONTROL HIGH VOLTAGE

In some areas, transmission circuit switching is a viable option for controlling high voltage/excessive charging conditions. Appendix A column 6 identifies the ISO Transmission Operating Guides that provide information for switching circuits to control high voltage.

D. LOAD MANAGEMENT FOR VOLTAGE/REACTIVE RELIABILITY

In severe cases of low voltage and/or inadequate reactive reserves, load management actions can be taken. Details on conditions when these actions can/shall be used and how they shall be implemented are provided in the ISO Transmission Operating Guides (as identified in Appendix A, column 7) and ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4) and ISO New England Operating Procedure No. 7 - Action in an Emergency (OP-7).
IV. RESPONSIBILITIES

This OP is based on the principle that voltage control is best achieved when action is taken as close as possible to the affected area. Voltage schedules and other reactive conditions shall be supervised by the generating station operators, transmission operators, LCC System Operators and ISO New England System Operators, each having a specific area of responsibility. Regardless of who requests or directs corrective measures, action must ultimately be taken by generating/transmission operators or LCC System Operators depending on who has "hands on" control of the reactive resources.

A. GENERATING AND TRANSMISSION STATIONS

Generating station and transmission operators are responsible for maintaining station service and other local voltage requirements and scheduled voltages at levels designated by ISO in the voltage schedules specified in OP-12, Appendix B, or as otherwise specified by ISO or an LCC. Generating station operators are also responsible for maintaining voltage schedules as otherwise specified by ISO or an LCC.

Normally, automatic voltage regulation works off the low side of the step-up transformer (generator terminals). Thus, in order to maintain a high side voltage schedule, manual intervention can be required to offset varying power flows through and voltage drops across the step-up transformer.

The Generator shall maintain the voltage schedule within the voltage schedule tolerance band, as specified in the "kV High" and "kV Low" levels for the appropriate load period, as indicated in the "Operational Voltage Schedules" columns of OP-12, Appendix B. Excursions outside of the prescribed voltage schedule tolerance band should be kept to a minimum. The Generator operator is expected to regularly check Generator high-side bus voltage against scheduled voltage and if the high-side voltage is outside the voltage schedule tolerance band, act to reestablish voltage within the tolerance band within 15 minutes. If a Generator high-side bus voltage drifts outside of its voltage schedule tolerance band, the Generator operator shall immediately notify the LCC when one of the following conditions is met:

1. the Generator is operating outside of its prescribed voltage schedule tolerance band for 15 minutes; or
2. the Generator operator determines that the Generator will be unable to return to its prescribed voltage schedule tolerance band within 15 minutes

A unit is not allowed to operate outside its voltage schedule tolerance band unless instructed to do so by ISO or the LCC. If a unit is not maintaining its voltage within the prescribed voltage schedule tolerance band for the appropriate load period for a period exceeding 15 minutes and has not notified the LCC (as described above), or is not following an alternative voltage schedule requested by the ISO or LCC closely, then the unit will be considered not to be operating in accordance with this procedure. If the voltage schedule directive differs between two Transmission Operators (i.e., ISO and LCC) to a single unit, both Transmission Operators will discuss and agree on the appropriate voltage schedule to communicate to the generator station operator.
When the unit is requested to be operated at a voltage schedule other than that specified in OP-12, Appendix B, the unit must still operate within the voltage schedule bandwidth indicated within OP-12, Appendix B. For example, if a unit was interconnected at 115 kV and had a +/- 2 kV voltage schedule tolerance band prescribed in OP-12, Appendix B, it would still have a +/- 2 kV voltage operating bandwidth at any other requested voltage schedule kV level.

NERC Reliability Standard VAR-002 - Generator Operations for Maintaining Network Voltage Schedules requires each Generator equipped with an Automatic Voltage Regulator (AVR) to operate in the automatic voltage control mode. Whenever the AVR operation is available, the Generator AVR will:

- Be in service and controlling voltage, and
- Remain in this configuration unless otherwise directed by the ISO or LCC System Operator.

When a Generator AVR is out-of-service, the Generator operator shall use an alternative method to control the Generator reactive output to meet the voltage or Reactive Power schedule. Actual or expected changes in AVR operating status must be reported in accordance with this procedure and with M/LCC 8 as follows:

1. Changes to AVR status must always be reported in Real-Time except when such reporting is done in advance by the Lead Market Participant, on Form NX-12D, for when it is routinely expected that a Generator will not operate with the AVR in service and controlling voltage (such as during Start Up or Shut Down), as described below. Such reporting shall occur whenever the AVR is removed from or placed into service unless such action is warranted by emergency plant conditions. Any problems that could interfere with proper operation of an AVR must also be reported. Such reporting shall be made to the following entities as soon as the AVR status change condition arises, as follows:
   - The Generator operator must report to the applicable LCC; and
   - The Lead Market Participant must report to ISO through their assigned Designated Entity (DE).

2. Changes to AVR status that occur during periods of time when Real-Time conditions are as described by the Lead Market Participant on Form NX-12D, in accordance with ISO OP-14, that pertain to when the Lead Market Participant routinely expects that its Generator will not operate with the AVR in service and controlling voltage (such as during Start Up or Shut Down) are not to be reported in Real-Time. When such conditions occur that match the conditions described on Form NX-12D, this serves as advance standing notification and Real-Time reporting is not required.

When unable to maintain scheduled station and local voltages with the means under their control, the generating station or transmission operators must notify their respective LCC System Operator (and local dispatch authority if appropriate).

Generator station operators are responsible to comply with the reactive capability verification process defined in Section II.C.
LCCs

LCCs are responsible for monitoring and supervising the following conditions within their territories:

1. Voltage schedules and limits,
2. Generator MVAR loadings, capabilities and reserves,
3. Shunt capacitor and reactor dispatches,
4. Transformer voltage schedules or fixed tap settings,
5. Synchronous condenser operation (requested via ISO by the LCC unless in emergency conditions),
6. MVAR flows between the AC system and HVDC facilities,
7. Static VAR Compensator operation (must be coordinated with ISO),
8. Line switching for voltage/reactive control (must be coordinated with ISO and, if warranted, with other LCCs),
9. Other predefined indicators of voltage/reactive security (e.g. a particular circuit flow, the status of specific Generators, area load level, etc.).

The LCCs are responsible for:

1. Detecting and correcting deviations from normal scheduled voltage/reactive operations
2. Responding to notifications by generating station or transmission operators of difficulty in maintaining station or other local voltage or reactive schedules
3. Responding to ISO requests to assist with inter-LCC or inter-Area problems.

The LCCs will notify/coordinate with ISO when there is a need to adjust the real power (MW) output of a Generator in order to adjust its MVAR output, and ISO will provide the direction to the Designated Entity/Generator Operator to adjust their Generator real power (MW) output. Unless an emergency condition warrants such action, the LCCs will not directly provide direction to the Generator Operator to adjust the real power output (MW) of their Generator in order to adjust its MVAR output.

The LCCs are authorized to exercise the following actions to correct voltage/reactive difficulties within their territories:

1. Direct voltage schedules and levels of reactive output and reserve on Generators, synchronous condensers and Static VAR Compensators,
2. Direct the use of shunt capacitors and reactors,
3. Direct the operation of LTC transformers.

When an LCC is unable to correct a voltage/reactive problem using the above actions or...
the LCC believes that the problem should be handled on a multi-LCC or inter-RCA basis, the LCC shall notify ISO and request assistance.

Before exercising any of the following voltage/reactive control actions, LCCs must notify ISO and coordinate their implementations:

1. Line switching,
2. Load management,
3. Unit voltage schedule change.

During the first quarter of each year, each LCC shall confirm the voltage schedule for each Generator within their operational footprint with the Lead Market Participant for that Generator and instruct each Generator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). Such annual transmittals by each LCC shall be to all of the following Generators:

1. Those listed in OP-12, Appendix B
2. Those listed in M/LCC 8, Attachment A
3. All other Generators for which the LCCs have specified voltage schedules

Each LCC shall use the template provided in OP-12, Appendix D for such transmittals and also, as the source of email addresses for the Lead Market Participant contacts, shall use the DE Contact Information posted on the Confidential Satellite Web site at: http://isoweb.iso-ne.com/satellite/NX-12_Generator_Information.php

On each such transmittal, the LCC shall copy the chair of the Voltage Task Force at email address: vtfcontact@iso-ne.com
B. ISO

ISO is responsible for general monitoring and supervision of voltage/reactive conditions in the New England RCA (115 kV and above). When system monitoring detects a problem within an LCC, ISO shall contact the LCC and request action.

When an LCC reports to ISO that it is not possible to correct an abnormal voltage/reactive-related operating condition at a station or LCC level, ISO shall assume direct responsibility for alleviating the problem. ISO is authorized to direct, through the appropriate LCC(s), all actions listed in the above LCC Section B and in addition any MW re-dispatching.

ISO is also responsible for monitoring and supervising voltage/reactive operations of inter-RCA ties. Abnormal voltage/reactive-related operating conditions may be noticed by ISO or appear in the form of requests from a neighboring Reliability Coordinator or companies for assistance. ISO shall inform the appropriate LCC(s) of the nature of the problem specifying: the pool or company involved, the location of the undesirable voltage/reactive condition and, general conditions aggravating the difficulty. ISO is authorized to work with/through the LCCs and use all Section B actions and MW re-dispatching to eliminate the problem.

When abnormal voltage/reactive operating conditions materialize, ISO may initiate a survey of key system parameters to better assess the nature and expanse of the conditions. Appendix C contains the survey forms that ISO will use. The forms are broken down based on LCC territories.

ISO shall report annually to NPCC about the status of the ISO-NE Generator Reactive Power Capability Verification Program including any changes in the verification process and provide copies of any changes to the Generator Owners and NPCC within 30 days of issue. ISO shall also report annually to NPCC any discrepancies between published (NX-12D) and demonstrated reactive capability.
## OP-12 REVISION HISTORY

### Document History
(This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

<table>
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<tr>
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<td>Rev 1</td>
<td>08/18/98</td>
<td>Updated to conform to RTO terminology</td>
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<td>Rev 2</td>
<td>02/01/05</td>
<td>Update References for NERC Version 0 Standards</td>
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<tr>
<td>Rev 3</td>
<td>05/06/05</td>
<td>Biennial Review by Procedure Owner. Updated former page 1 and added &quot;uncontrolled to remaining pages; Corrected and added Reference titles. Defined terms and approved acronyms for use in this document: ISO New England (ISO); Local Control Center (LCC); Reliability Coordinator Area (RCA) Inserted new language applicable to meeting requirements of NPCC Directory #10 &amp; NERC Reliability Standard VAR-002 New Section II.C - Verification of Generator Reactive Power Capability. Section IV added related responsibilities to Generators and ISO.</td>
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<td>Rev 4</td>
<td>06/04/10</td>
<td>Biennial Review by Procedure Owner. Updated former page 1 and added &quot;uncontrolled to remaining pages; Corrected and added Reference titles. Defined terms and approved acronyms for use in this document: ISO New England (ISO); Local Control Center (LCC); Reliability Coordinator Area (RCA) Inserted new language applicable to meeting requirements of NPCC Directory #10 &amp; NERC Reliability Standard VAR-002 New Section II.C - Verification of Generator Reactive Power Capability. Section IV added related responsibilities to Generators and ISO.</td>
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<td>Replaced page numbers in footers with Page X of Y format; References Section II replaced &quot;...stabilizer...&quot; with &quot;...Stabilizer...&quot;; Section II.A: defined voltage schedules and added reference to Appendix B Section II.C: in 1st paragraph, replaced &quot;...satisfy both...&quot; with &quot;...satisfy all...&quot; Section II.C: as new item II.C.3, added language to exempt units that are not NERC registered from testing requirements; Section II.C: as a new paragraph at the end of the section, added language to clarify testing requirements for units on extended outage; Section III.C: deleted &quot;...in the Boston area...&quot;; Section IV A: inserted &quot;Whenever AVR operation is available,&quot; Section IV.B.9: deleted the comma (,) at the beginning of the item. Section IV.C.3’s paragraph replaced &quot;...MW...&quot; with &quot;...MW...&quot;</td>
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<td>References Section, deleted NERC Reliability Standard MOD-025, corrected titles of items 2 &amp; 8; Section I: clarified that only permanent operating guides are listed in Table 1 of OP-12, App A and pointed out that additional voltage/reactive instructions may reside in temporary operating guides; Section II.A: significant expansion to section, with added details on voltage schedule requirements for units; Section II.B: deleted name of OP-14 and added “Reliability Coordinator Area”; Section III.A: added phrase “OP-12, App B and in”; Section IV: removed “Local Control Center” name leaving the abbreviation and removed “station” reference in two locations; Section IV.A: significant enhancement describing the revised OP-12, App B document and the use of the information / voltage schedules found within OP-12; App B. Described AVR status change requirements in detail. Changed used of the word “station” in the 2nd to last paragraph; Section IV.B: Changed used of the word “station” in the 2nd set of numbered items. Added requirement of the LCCs to annually contact and confirm the voltage schedule for units. Added provision to allow a 15-minute window for excursions outside of the prescribed voltage schedule tolerance band;</td>
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### Revision Notes
- Effective Date: draft
- Draft: April 13, 2012

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### CONVEX Voltage & Reactive Schedule for Generators

- **Legend**
  - Sched = Schedule
  - Max = Maximum
  - Min = Minimum
  - MVar Out = Gross Lagging based on NX-12D and operational data
  - MVar In = Gross Leading based on NX-12D and operational data
  - S-SCC = Summer Seasonal Claimed Capability

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| KLEEN ENERGY ST | 357  | 360  | 354  | 357  | 360  | 354  | 125      | -112 | 362  |
| LAKE ROAD 1    | 357  | 360  | 354  | 357  | 360  | 354  | 187      | -81  | 362  |
| LAKE ROAD 2    | 357  | 360  | 354  | 357  | 360  | 354  | 184      | -80  | 362  |
| LAKE ROAD 3    | 357  | 360  | 354  | 357  | 360  | 354  | 181      | -78  | 362  |
| MASS POWER     | 119  | 120  | 117  | 119  | 120  | 117  | 104      | -38  | 121  |
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## CONVEX Voltage & Reactive Schedule for Generators

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<th>Operational Voltage Schedules - Heavy Load Period</th>
<th>Operational Voltage Schedules - Light Load Period</th>
<th>Reactive Capability</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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## CONVEX Voltage & Reactive Schedule for Generators

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period</th>
<th>Operational Voltage Schedules - Light Load Period</th>
<th>Reactive Capability</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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<tr>
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<td>Tolerance Band</td>
<td>Sched kV</td>
<td>Tolerance Band</td>
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<td>WATERSIDE</td>
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<td>120 117</td>
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<td>119 115</td>
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<td>WEST SPRINGFIELD 2</td>
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<td>119 115</td>
<td>117</td>
<td>119 115</td>
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</table>

Note: Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

1 Heavy load is from 0700-2200 Monday through Saturday except Holidays.

2 Light load is all other hours.
## CONVEX Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Data from NX-9</th>
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<tr>
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<td>Available MVar</td>
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<tr>
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<tr>
<td>AMHERST 10K</td>
<td>1 @ 14.4</td>
</tr>
<tr>
<td>BERLIN 11K; 12K</td>
<td>2 @ 37.8</td>
</tr>
<tr>
<td>BERLIN 13K</td>
<td>1 @ 50.4</td>
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<tr>
<td>BRANFORD 10K</td>
<td>1 @ 37.8</td>
</tr>
<tr>
<td>CANTON 11K; 12K</td>
<td>2 @ 25.2</td>
</tr>
<tr>
<td>DARIEN 10K</td>
<td>1 @ 37.8</td>
</tr>
<tr>
<td>EAST SHORE 1K; 2K</td>
<td>2 @ 42.0</td>
</tr>
<tr>
<td>FRANKLIN DRIVE 10K</td>
<td>1 @ 37.8</td>
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<tr>
<td>FROST BRIDGE 11K; 12K; 13K</td>
<td>3 @ 50.4</td>
</tr>
<tr>
<td>FROST BRIDGE 21K; 22K</td>
<td>2 @ 50.4</td>
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<tr>
<td>GLENBROOK 11K; 12K</td>
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<td>GLENBROOK 13K; 14K</td>
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<td>GLENBROOK 21K; 22K</td>
<td>2 @ 36.0</td>
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<tr>
<td>GLENBROOK 23k</td>
<td>1 @ 37.8</td>
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<tr>
<td>GLENBROOK 24k</td>
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<tr>
<td>MANCHESTER 11K; 12K; 13K</td>
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<tr>
<td>MONTVILLE 11K; 12K</td>
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<td>MYSTIC 21K; 22K</td>
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## CONVEX Transmission Capacitors

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<tr>
<td>STONY HILL 21K; 22K</td>
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<td>WATERSIDE 10K</td>
<td>1 @ 37.8</td>
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<tr>
<td>WOODLAND 21K; 22K</td>
<td>2 @ 14.4</td>
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* Sackett 1K capacitor is out of service until further notice
## CONVEX Transmission Reactors

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<th>System Nominal Voltage (kV)</th>
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<tr>
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<td>NORWALK R1; R2</td>
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<td>NORWALK JUNCTION F1; F2</td>
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<td>SINGER R1; R2; R3; R4</td>
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## CONVEX Voltage & Reactive Schedules for Transmission STATCOMs

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<th>Operational Voltage Schedules Heavy Load Period¹</th>
<th>Operational Voltage Schedules Light Load Period²</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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¹ Heavy load is from 0700-2200 Monday through Saturday except Holidays.
² Light load is all other hours.

Legend
- Sched = Schedule
- Max = Maximum
- Min = Minimum

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Hardcopy is Uncontrolled
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## CONVEX Voltage Schedules for Autotransformers with LTCs

**Legend**
- Sched = Schedule
- Max = Maximum
- Min = Minimum
- Auto = Automatic

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<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
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<th>Voltage Control Bandwidth (kV)</th>
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<tr>
<td>BERKSHIRE 1X</td>
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<td>109-121</td>
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<td>BERKSHIRE 2X</td>
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<td>112-119</td>
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<td>111-121</td>
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<td>116-121</td>
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### CONVEX Voltage Schedules for Autotransformers with LTCs

*Singer 1X is a GSU with tap changing options. It is LTC capable but is normally operated in manual.*
### Maine Voltage & Reactive Schedule for Generators

**Legend**
- **Sched** = Schedule
- **Max** = Maximum
- **Min** = Minimum
- **MVar Out** = Gross Lagging based on NX-12D and operational data
- **MVar In** = Gross Leading based on NX-12D and operational data
- **MVA SCC** = Summer Seasonal Claimed Capability

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period¹</th>
<th>Operational Voltage Schedules - Light Load Period¹</th>
<th>Reactive Capability</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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<td>Tolerance Band</td>
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¹ Period

Revision 28 Effective Date: draft

Hardcopy is Uncontrolled
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### Maine Voltage & Reactive Schedule for Generators

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period¹</th>
<th>Operational Voltage Schedules - Light Load Period²</th>
<th>Reactive Capability</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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<tr>
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<td>Tolerance Band</td>
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<td>MVAr In @ Min Manual</td>
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<td>kV Sched High Low</td>
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</table>

Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

¹ Heavy load is from 0700-2200 Monday through Saturday except Holidays.

² Light load is all other hours.
## Maine Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
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<tbody>
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<td>HEYWOOD KC1</td>
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<td>KEENE RD</td>
<td>1 @ 15</td>
<td>115</td>
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<tr>
<td>KIMBALL ROAD KC1; KC2</td>
<td>2 @ 30</td>
<td>115</td>
</tr>
<tr>
<td>LARRABEE ROAD KC1</td>
<td>1 @ 30</td>
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</tr>
<tr>
<td>MAGUIRE ROAD KC1</td>
<td>1 @ 50.86</td>
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<td>MASON KC2; KC3</td>
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<tr>
<td>MAXCYS KC1; KC2</td>
<td>2 @ 50</td>
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<td>ORRINGTON KC1; KC2; KC3</td>
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<td>115</td>
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<td>RILEY KC1</td>
<td>1 @ 30</td>
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<td>RUMFORD IP KC1</td>
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<td>SANFORD KC1</td>
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<tr>
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<td>STARKS KC1; KC2</td>
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## Maine Transmission Reactors

<table>
<thead>
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## Maine Voltage & Reactive Schedules for Transmission Static VAR Compensator

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<tr>
<th>Location</th>
<th>Operational Voltage Schedules Heavy Load Period&lt;sup&gt;1&lt;/sup&gt;</th>
<th>Operational Voltage Schedules Light Load Period&lt;sup&gt;2&lt;/sup&gt;</th>
<th>Max/Min Acceptable Voltage Schedule Range</th>
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<td>348</td>
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<sup>1</sup> See M/LCC 9 and M/LCC 9 Attachment B for a detailed description of the voltage / reactive scheduling for the Chester SVC.

<sup>2</sup> Heavy load is from 0700-2200 Monday through Saturday except Holidays.

<sup>3</sup> Light load is all other hours.
<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
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<tbody>
<tr>
<td>ALBION ROAD T1</td>
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<td>LARRABEE ROAD T1</td>
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<td>118-120</td>
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<tr>
<td>SUROWIEC T1</td>
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<td>A</td>
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<td>16</td>
<td>-16</td>
<td>118-120</td>
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* Transformer tap adjusted to maintain the appropriate voltage schedule based on prevailing system conditions

** This transformer LTC is run in manual when WEC is online.
## New Hampshire Voltage & Reactive Schedule for Generators

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period</th>
<th>Operational Voltage Schedules - Light Load Period</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
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<td>14 0 121 109</td>
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Note: Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

*Granite units CT1 & CT2 are located in the REMVEC Section

1 Heavy load is from 0700-2200 Monday through Saturday except Holidays.

2 Light load is all other hours.
## New Hampshire Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
</tr>
</thead>
<tbody>
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<td>THREE RIVERS J1160; J1161</td>
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<td>WHITE LAKE J1167</td>
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### New Hampshire Transmission Reactors

<table>
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<th>Substation Location</th>
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### New Hampshire Voltage Schedules for Autotransformers with LTCs

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<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
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<td>119.3</td>
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* This transformer LTC is run in manual when Merrimack units are on line.
### NSTAR Voltage & Reactive Schedule for Generators

Legend:

- **Sched** = Schedule
- **Max** = Maximum
- **Min** = Minimum
- **MVAR Out** = Gross Lagging based on NX-12D and operational data
- **MVAR In** = Gross Leading based on NX-12D and operational data
- **S-SCC** = Summer Seasonal Claimed Capability

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period</th>
<th>Operational Voltage Schedules - Light Load Period</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tolerance Band (kV)</td>
<td>Tolerance Band (kV)</td>
<td>MVAR Out @ S-SCC</td>
<td>MVAR In @ Min Manual</td>
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<td>Max kV Min kV</td>
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<td>ANP BLACKSTONE 2</td>
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<td>356 359 353</td>
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<td>CANAL 1</td>
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## NSTAR Voltage & Reactive Schedule for Generators

**Legend**
- Sched = Schedule
- Max = Maximum
- Min = Minimum
- MVAr Out = Gross Lagging based on NX-12D and operational data
- MVAr In = Gross Leading based on NX-12D and operational data
- S-SCC = Summer Seasonal Claimed Capability

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period¹</th>
<th>Operational Voltage Schedules - Light Load Period¹</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
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<td>THOMAS A. WATSON 2</td>
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</table>

Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

¹ Heavy load is from 0700-2200 Monday through Saturday except Holidays.
² Light load is all other hours.
### NSTAR Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAKER STREET C1; C2</td>
<td>2 @ 54</td>
<td>115</td>
</tr>
<tr>
<td>BARNSTABLE C1</td>
<td>1 @ 35.3</td>
<td>115</td>
</tr>
<tr>
<td>CHELSEA C1</td>
<td>1 @ 36.7</td>
<td>115</td>
</tr>
<tr>
<td>DOVER C1</td>
<td>1 @ 53.6</td>
<td>115</td>
</tr>
<tr>
<td>FALMOUTH TAP C1</td>
<td>1 @ 35.3</td>
<td>115</td>
</tr>
<tr>
<td>FRAMINGHAM C1</td>
<td>1 @ 53.6</td>
<td>115</td>
</tr>
<tr>
<td>HARWICH C1</td>
<td>1 @ 21.2</td>
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<tr>
<td>HARTWELL C1</td>
<td>1 @ 36.7</td>
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<tr>
<td>HYANNIS JCT. C1</td>
<td>1 @ 39</td>
<td>115</td>
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<tr>
<td>K-STREET C1; C2</td>
<td>2 @ 53.6</td>
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<tr>
<td>LEXINGTON C1</td>
<td>1 @ 54</td>
<td>115</td>
</tr>
<tr>
<td>MASHPEE C1</td>
<td>1 @ 35.3</td>
<td>115</td>
</tr>
<tr>
<td>MYSTIC C1</td>
<td>1 @ 53.6</td>
<td>115</td>
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<td>ORLEANS C1</td>
<td>1 @ 13.6</td>
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<tr>
<td>SUDBURY C1</td>
<td>1 @ 49.5</td>
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<tr>
<td>WING LANE STATION C1</td>
<td>1 @ 35.3</td>
<td>115</td>
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<tr>
<td>WEST FRAMINGHAM C1</td>
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### NSTAR Transmission Reactors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Data from NX-9</th>
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<tbody>
<tr>
<td></td>
<td>Available MVAR</td>
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<tr>
<td>EDGAR R1; R2</td>
<td>2 @ -40</td>
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<tr>
<td>K-STREET R1</td>
<td>1 @ -80</td>
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<tr>
<td>K-STREET 345-R1; 345-R2</td>
<td>2 @ -70 Fixed; -90 Variable</td>
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<tr>
<td>LEXINGTON 345-R1</td>
<td>1 @ -70 Fixed; -90 Variable</td>
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<tr>
<td>MYSTIC R1</td>
<td>1 @ -80</td>
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<tr>
<td>MYSTIC 345-R1</td>
<td>1 @ -70 Fixed; -90 Variable</td>
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<tr>
<td>NORTH CAMBRIDGE R1; R2</td>
<td>2 @ -80</td>
</tr>
<tr>
<td>NORTH CAMBRIDGE 345-R1</td>
<td>1 @ -70 Fixed; -90 Variable</td>
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<tr>
<td>STOUGHTON 345-R1; 345-R2; 345-R3; 345-R4</td>
<td>4 @ -70 Fixed; -90 Variable</td>
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<tr>
<td>WEST WALPOLE 345-R1</td>
<td>1 @ -70 Fixed; -90 Variable</td>
</tr>
<tr>
<td>WOBURN R1; R2; R3</td>
<td>3 @ -80</td>
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</table>
### NSTAR Voltage Schedules for Autotransformers with LTCs

<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Sched Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
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<tbody>
<tr>
<td>WOBURN 345A</td>
<td>345/115</td>
<td>M</td>
<td>N/A*</td>
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<td>103.96-126.45</td>
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* Transformer tap adjusted to maintain the appropriate voltage schedule based on prevailing system conditions
# NSTAR Voltage & Reactive Schedules for Transmission Static VAR Compensator

<table>
<thead>
<tr>
<th>Location</th>
<th>Operational Voltage Schedules - Heavy Load Period$^1$</th>
<th>Operational Voltage Schedules - Light Load Period$^1$</th>
<th>Available MVAR</th>
<th>Nominal Voltage Schedule Range</th>
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<td>kV Sched</td>
<td>kV High</td>
<td>kV Low</td>
<td>kV Sched</td>
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<tr>
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<td>NA</td>
<td>121</td>
<td>109</td>
<td>NA</td>
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</table>

* Under normal operational conditions, the SVC will be operating with a zero (0) MVAR output, ready to respond to faults in the network. During the first 2 seconds, the MVAR output is 225 MVAR. After that, the MVAR output is rapidly reduced to a maximum of 125 MVAR, which can be sustained for up to 30 minutes.

$^1$ Heavy load is from 0700-2200 Monday through Saturday except Holidays.

$^2$ Light load is all other hours.
## REMVEC Voltage & Reactive Schedule for Generators

<table>
<thead>
<tr>
<th>Units</th>
<th>Voltage Schedules - Heavy Load Period</th>
<th>Voltage Schedules - Light Load Period</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
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<tr>
<td>BEAR SWAMP 1 PUMP</td>
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<tr>
<td>BEAR SWAMP 2 GEN</td>
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<td>FPL RISE ST 1</td>
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**Legend**
- **Sched** = Schedule
- **Min** = Minimum
- **Max** = Maximum
- **MVAR Out** = Gross Lagging based on NX-12D and operational data
- **MVAR In** = Gross Leading based on NX-12D and operational data
- **S-SCC** = Summer Seasonal Claimed Capability

**Units**
- **Operational Voltage Schedules**
- **Tolerance Band**
  - **kV Sched**
  - **kV High**
  - **kV Low**
- **Acceptable Max/Min Voltage Schedule Range**
  - **kV Load**
  - **kV Max**
  - **kV Min**

---

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### REMVEC Voltage & Reactive Schedule for Generators

**Legend**
- Sched = Schedule
- Max = Maximum
- Min = Minimum
- MVA r Out = Gross Lagging based on NX-12D and operational data
- MVA r In = Gross Leading based on NX-12D and operational data
- S-SCC = Summer Seasonal Claimed Capability

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period¹</th>
<th>Operational Voltage Schedules - Light Load Period¹</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
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</thead>
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<td>RESCO SAUGUS</td>
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<td>RIDGEWOOD</td>
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<td>WMI MILLBURY</td>
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Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

* The Granite Ridge ST unit is located in New Hampshire Section.
¹Heavy load is from 0700-2200 Monday through Saturday except Holidays.
²Light load is all other hours.

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## REMVEC Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
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</thead>
<tbody>
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<td>KENT COUNTY C5; C6</td>
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<tr>
<td>MONROE C11; C12</td>
<td>2 @ 31.5</td>
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<td>MONROE C21; C22</td>
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<tr>
<td>MILBURY C1; C3</td>
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<td>NORTHBORO RD. C6</td>
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<td>NORTHBORO RD. C3; C4</td>
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<td>PRATTS JCT 4A</td>
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<td>SANDY POND F13; F23*</td>
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<td>TEWKSBURY C1; C2</td>
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</table>

*These capacitors are used to control Sandy Pond voltage when Phase II is ON with limited system voltage support. If Phase II is OFF, these capacitors can be used to support system voltages.*
## REMVEC Transmission Reactors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Data from NX-9</th>
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<tbody>
<tr>
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<tr>
<td>SANDY POND V1 - R11, V2 - R21, V2 - R22*</td>
<td>3 @ -160</td>
</tr>
</tbody>
</table>

*These reactors are used to control Sandy Pond voltage when Phase II is ON with limited system voltage support. If Phase II is OFF, these reactors can be used to support system voltages.
# REMVEC Voltage & Reactive Schedules for Autotransformers with LTCs

<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
</tr>
</thead>
</table>

**Legend**
- Sched = Schedule
- Max = Maximum
- Min = Minimum
- Auto = Automatic
## VELCO Voltage & Reactive Schedule for Generators

**Legend**

- **Sched**: Schedule
- **Max**: Maximum
- **Min**: Minimum

**MVAR Out** = Gross Lagging based on NX-12D and operational data

**MVAR In** = Gross Leading based on NX-12D and operational data

**S-SCC**: Summer Seasonal Claimed Capability

### Units

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules - Heavy Load Period¹</th>
<th>Operational Voltage Schedules - Light Load Period²</th>
<th>Reactive Capability</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tolerance Band</td>
<td>Tolerance Band</td>
<td>MVARs Out @ Min Manual</td>
<td>MVAR In @ Manual</td>
</tr>
<tr>
<td></td>
<td>kv</td>
<td>kv</td>
<td>kv</td>
<td>kv</td>
</tr>
<tr>
<td></td>
<td>Sched</td>
<td>High</td>
<td>Low</td>
<td>Sched</td>
</tr>
<tr>
<td>GRANITE SYNC COND</td>
<td>117.0</td>
<td>118.5</td>
<td>115.0</td>
<td>117.0</td>
</tr>
<tr>
<td>VERMONT YANKEE</td>
<td>357</td>
<td>360</td>
<td>354</td>
<td>357</td>
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</table>

Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

¹Heavy load is from 0700-2200 Monday through Saturday except Holidays.

²Light load is all other hours.
### VELCO Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BENNINGTON C31, C32</td>
<td>2 @ 12.42</td>
<td>115</td>
</tr>
<tr>
<td>BERLIN C87</td>
<td>1 @ 24.8</td>
<td>115</td>
</tr>
<tr>
<td>COOLIDGE C91; C92</td>
<td>2 @ 25.0</td>
<td>115</td>
</tr>
<tr>
<td>ESSEX #1 C34</td>
<td>1 @ 24.3</td>
<td>115</td>
</tr>
<tr>
<td>ESSEX C35; C36; C37; C38; C39</td>
<td>5 @ 24.8</td>
<td>115</td>
</tr>
<tr>
<td>GEORGIA C41</td>
<td>1 @ 24.8</td>
<td>115</td>
</tr>
<tr>
<td>HARTFORD C40</td>
<td>1 @ 25.0</td>
<td>115</td>
</tr>
<tr>
<td>GRANITE C61; C62; C66</td>
<td>3 @ 25.0</td>
<td>115</td>
</tr>
<tr>
<td>LYNDONVILLE C21; C23</td>
<td>2 @ 12.50</td>
<td>115</td>
</tr>
<tr>
<td>MIDDLEBURY VB72</td>
<td>1 @ 22.9</td>
<td>115</td>
</tr>
<tr>
<td>NORTH RUTLAND C71</td>
<td>1 @ 24.8</td>
<td>115</td>
</tr>
<tr>
<td>SANDBAR C82</td>
<td>1 @ 24.8</td>
<td>115</td>
</tr>
<tr>
<td>VERMONT YANKEE C50; C51</td>
<td>2 @ 15.0</td>
<td>115</td>
</tr>
<tr>
<td>VERMONT YANKEE C52</td>
<td>1 @ 30.0</td>
<td>115</td>
</tr>
<tr>
<td>WEST RUTLAND C45; C46</td>
<td>2 @ 25.0</td>
<td>115</td>
</tr>
<tr>
<td>WILLISTON C83</td>
<td>1 @ 25.2</td>
<td>115</td>
</tr>
</tbody>
</table>

*These capacitors are used to control Highgate voltage when the Highgate Converter is ON with limited system voltage support. If the Highgate Converter is OFF, 80 MVAR capacitors are available to provide voltage support when enabled by operators.
### VELCO Transmission Reactors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Data from NX-9</th>
<th>Available MVar</th>
<th>System Nominal Voltage (kV)</th>
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</thead>
<tbody>
<tr>
<td>COOLIDGE R41; R42</td>
<td></td>
<td>2 @-34 Fixed -26 Variable</td>
<td>345</td>
</tr>
<tr>
<td>NEW HAVEN R37</td>
<td></td>
<td>1 @-34 Fixed -26 Variable</td>
<td>345</td>
</tr>
<tr>
<td>VERNON_VT R10</td>
<td></td>
<td>1@-60</td>
<td>345</td>
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</table>
### VELCO Voltage & Reactive Schedules for Transmission STATCOMs

<table>
<thead>
<tr>
<th>Location</th>
<th>Operational Voltage Schedules - Heavy Load Period(^1)</th>
<th>Operational Voltage Schedules - Light Load Period(^1)</th>
<th>Acceptable Max/Min Voltage Schedule Range</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>KV Sched High Low</td>
<td>KV Sched High Low</td>
<td>Available Nominal Voltage MVAR (kV) kV Max kV Min</td>
</tr>
<tr>
<td>ESSEX STATCOM</td>
<td>117 119 115</td>
<td>117 119 115</td>
<td>-65 / +85 115 119 112</td>
</tr>
</tbody>
</table>

\(^1\) Heavy load is from 0700-2200 Monday through Saturday except Holidays.
\(^2\) Light load is all other hours.
## VELCO Voltage Schedules for Autotransformers with LTCs

<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>COOLIDGE XF</td>
<td>345/115</td>
<td>M</td>
<td>117</td>
<td>33</td>
<td>1</td>
<td>N/A</td>
</tr>
<tr>
<td>GRANITE T1</td>
<td>230/115</td>
<td>A</td>
<td>234</td>
<td>16</td>
<td>-16</td>
<td>237 - 230</td>
</tr>
<tr>
<td>GRANITE T2</td>
<td>230/115</td>
<td>A</td>
<td>234</td>
<td>16</td>
<td>-16</td>
<td>237 - 230</td>
</tr>
<tr>
<td>WEST RUTLAND T1</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7 - 114.1</td>
</tr>
<tr>
<td>WEST RUTLAND T2</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7 - 114.1</td>
</tr>
<tr>
<td>NEW HAVEN T1</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7 - 114.1</td>
</tr>
<tr>
<td>NEW HAVEN T2</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7 - 114.1</td>
</tr>
</tbody>
</table>

*New Haven and West Rutland transformers operated in tandem*
## OP-12, Appendix B Revision History

**Document History** (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

<table>
<thead>
<tr>
<th>Rev. No.</th>
<th>Date</th>
<th>Reason</th>
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</thead>
<tbody>
<tr>
<td>Rev 1</td>
<td>05/23/03</td>
<td></td>
</tr>
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<td>Rev 2</td>
<td>08/05/03</td>
<td></td>
</tr>
<tr>
<td>Rev 3</td>
<td>07/25/04</td>
<td></td>
</tr>
<tr>
<td>Rev 4</td>
<td>11/09/04</td>
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<tr>
<td>Rev 5</td>
<td>02/01/05</td>
<td>Updated to conform to RTO terminology</td>
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<td>Rev 6</td>
<td>05/06/05</td>
<td>Update for initiation of VELCO Local Control Center</td>
</tr>
<tr>
<td>Rev 7</td>
<td>06/02/05</td>
<td>Update information resulting from VTF review</td>
</tr>
<tr>
<td>Rev 8</td>
<td>09/07/06</td>
<td>Updated information resulting from VTF review</td>
</tr>
<tr>
<td>Rev 9</td>
<td>10/26/06</td>
<td>Corrected MVAR value for Rumford</td>
</tr>
<tr>
<td>Rev 10</td>
<td>09/17/07</td>
<td>Updated information resulting from ISO Operations Support Services review</td>
</tr>
<tr>
<td>Rev 11</td>
<td>03/04/08</td>
<td>Revised for NSTAR LCC status</td>
</tr>
<tr>
<td>Rev 12</td>
<td>05/22/08</td>
<td>Completely reformatted to allow better use and ease making future revisions. Updated information resulting from VTF review</td>
</tr>
<tr>
<td>Rev 13</td>
<td>06/26/08</td>
<td>Updated information resulting from VTF review.</td>
</tr>
<tr>
<td>Rev 14</td>
<td>09/16/08</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 15</td>
<td>04/21/09</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 16</td>
<td>06/05/09</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 17</td>
<td>09/24/09</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 18</td>
<td>10/30/09</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 19</td>
<td>12/15/09</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 20</td>
<td>02/26/10</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 21</td>
<td>05/24/10</td>
<td>Minor reformatting of tables to make sure date is displayed consistently; Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 22</td>
<td>08/17/10</td>
<td>Updated information resulting from VTF review and new test results.</td>
</tr>
<tr>
<td>Rev 23</td>
<td>05/25/11</td>
<td>Replaced page numbers with Page X of Y format; Updated information resulting from VTF review.</td>
</tr>
<tr>
<td>Rev 24</td>
<td>07/21/11</td>
<td>CONVEX Generators added Kleen Energy station units CT1, CT2 &amp; ST data rows; New Hampshire Capacitors added Oak Hill capacitors (J1179; J1180) data row; NSTAR Capacitors added Chelsea capacitor C1 data row; REMVEC Comerford Capacitors added unit designations for reactors (R21-24 &amp; R31-34); REMVEC Comerford Reactors corrected reactor data MVAR (now 20.2) and Nominal Voltage (now 14.3)</td>
</tr>
</tbody>
</table>
Biennial review by procedure owner;  
**CONVEX** – Generators: Added data row for the following:  
A. L. Pierce  
Bridgeport HBR 4  
Bridgeport RESCO  
Cos Cob 10, 11, 12, 13, 14  
Devon 10, 11, 12, 13, 14, 15, 16, 17, 18  
Middletown 10, 12, 13, 14, 15  
New Haven HBR 2, 3, 4  
Norwalk HBR 3  
South Meadow 11, 12, 13, 14  
Tunnel  
Wallingford REFUSE  
Waterbury  
Waterside  
Modified the MVARs OUT for New Haven HBR  
Modified the MVARs IN min value for Northfield P1, P2, P3, P4  
**CONVEX** – Capacitors, Added an asterisk (*) to Sackett 1K & added a foot note  
**CONVEX** – Autotransformers with LTCs, Modified:  
- Barbour Hill 1X Schedule voltage and voltage control bandwidth  
- Manchester 4X, 5X, 6X Scheduled voltage  
North Bloomfield 5X Scheduled voltage  
Maine – Generators, added new data rows for Cape GT 4 & Cape GT 5  
Maine Static Var Compensator: reattributed note with asterisk  
Maine – Autotransformers with LTCs, Modified the LTC setting (Auto/Manual) and modified asterisks for this column for:  
- Keene Road  
- Orrington T1, T2  
New Hampshire – Generators, Added new data row for:  
- Merrimack CT1, CT2  
- Tamworth  
New Hampshire – Autotransformers with LTCs,  
- Added data row for Deerfield TB28  
- Fitzwilliam added “TB34” to station name;  
- Littleton TB41 modified scheduled voltage and Voltage Control Bandwidth;  
- Saco-Valley added “PS1” to station name  
**NSTAR** – Generators, Added new data row for:  
- Dartmouth 3  
**REMVEC** – Generators, Added new data row for:  
- Cleary 8  
- RESCO Saugus  
- Somerset Jet2  
- Waters River Jet2  
- WMI Millbury  
- Modified the MVARs Out and In for L’ENERGIA  
**REMVEC** – Capacitors, Added data row for Kent County C5, C6  
**VELCO** – Generators, Modified MVARs out for Vermont Yankee  
**VELCO** – Capacitors, Added new data row for:  
- Lyndonville C21, C23  
- West Rutland C45, C46
<table>
<thead>
<tr>
<th>Date</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>05/30/12</td>
<td>CONVEX – Generators, Modified data row for the following: Middletown 12, 13, 14 &amp; 15 Voltage Heavy Load/Light Load Sched, Max &amp; Min values all changed. Waterside Voltage Schedules both Heavy/Light kV Min values. West Springfield Heavy/Light kV Min values. Maine – Generators, Modified data rows for AEL Livermore Voltage Schedules Heavy/Light Load, kV Sched values; Bucksport Voltage Schedules Heavy/Light Load, kV min values; Harris Hydro G1, MVARS Out @ S-SCC values; Rumford Power GT, Voltage Schedules Heavy/Light Load, kV Sched values; Stratton Energy, MVARS out @ S-SCC and MVARS In @ Min Manual, Load values; VERSO AEC #1, #2 &amp; #3, Voltage Schedules Heavy/Light Load, kV Sched values; Maine – Static VAR Compensator, Modified the data row for: Chester SVC, Available MVAR values. REMVEC – Generators, Modified data row for: ANP Bellingham 1, MVARS IN @ MIN MANUAL Load value. Manchester 10/10A MVARS IN @ MIN MANUAL Load value.</td>
</tr>
<tr>
<td>03/25/13</td>
<td>CONVEX: AES Thames was deleted; Cabot generator was added; Berkshire Power leading capability was changed to -65 MVAR; Bridgeport Energy lagging capability was changed to 296 MVAR; Kleen Energy the lagging and leading capability (99 MVAR, 99 MVAR and 125 MVAR) and (-91 MVAR, -91 MVAR and -112 MVAR); Mass Power the lagging and leading capabilities were changed to 104 MVAR and -38 MVAR; Mount Tom lagging capability was changed to 17 MVAR; Northfield 2G lagging and leading capabilities changed to 136 MVAR and -103 MVAR; Norwalk Harbor 1 and 2 leading capability were changed to -28 and -27 MVAR; East Devon 2X LTC setting changed to Manual; Stonybrook 2B leading capability changed to -20 MVAR; Wallingford Energy 1 &amp; 4 lagging capabilities changed to 26 &amp; 27 MVAR. Maine: Cape 4 and Cape 5 changed leading capability to -2.7 and 2.9 MVAR; Rollsins Wind and Stetson Wind were added; Epping Tap capacitors bank was added (10.2 MVAR); Larrabee two reactors were added (2@40 MVAR); The nominal voltage was changed for Orrington and Surowiec reactors to 13.8 kV; Chester SVC reactive capability was changed to -123.29/448.32 MVAR; Larrabee 345/115 transformer was added. Schiller 6 leading capability changed to -22 MVAR. New Hampshire: Granite Reliable Wind was added. NSTAR: Mystic 7 leading capability was changed to -183 MVAR; Voltage schedule was changed for ANP Blackstone 1 &amp; 2; Canal 1, 2; Dartmouth Power; NEA Bellingham; Pilgrim; SEMass; Hartwell capacitor bank added (1@36.7 MVAR). REMVEC: Voltage schedule was changed for ANP Bellingham 1 &amp; 2, Brayton 3 &amp; 4 and Ocean State 1 &amp; 2; ANP Bellingham 2 leading capability changed to -83 MVAR; Bearswamp 1 Gen leading capability changed to -55 MVAR; Brayton 1 leading capability changed to -93 MVAR; Salem Harbor 1 &amp; 2 deleted; Comerford capacitors banks and reactors were renamed to Monroe; Sandy Pond C11 &amp; C21 available MVAR changed to 99 MVAR. VELCO: Capacitors - Georgia replaced C80 with C41; Granite deleted C64, available MVAr changed to 3; Reactor s@ New Haven deleted data row; Two reactors were added to Coolidge (-34 MVAR fixed and -26 MVAR is variable).</td>
</tr>
</tbody>
</table>
Biennial review by procedure owner:

Complete format change for entire document:
- Changed the title of this appendix to 'Voltage and Reactive Schedules';
- Deleted reference to 'survey' in the header of pages and columns;
- Changed title for Capacitors and Reactors tables and in the 'Contents' section;
- Changed format of appendix; add new columns for Generators: 'acceptable voltage schedule range';
- Changed data for operational voltage schedule range for Generators;
- Changed the header to the columns to reflect all changes above;
- Moved the "Heavy Load" and "Light Load" periods definitions to the Generator sections;
- Deleted reference to "Interconnection Agreements" in the general note under the Generator tables;
- Changed the format for 'MVARs' to 'MVAr';
- Modified the definition of 'MVAr In' and 'MVAr Out' in the Generator sections;
- Changed the 'MVAr In' & 'MVAr Out' columns title to 'Reactive Capability' in the Generator sections;

**CONVEX**

- Deleted Devon 10, Middletown 10, Norwalk Harbor 3, and Wallingford Refuse generators;
- Deleted comment for Cross Sound Cable;
- Changed Northfield and Stony Brook units heavy & light loads voltage schedules to 357 kV;
- Added Amherst 10K, and Podick 10K capacitors; Added Beseck R1 reactor;
- Added Agawam 1X and 2X autotransformers; Removed Ludlow 1X autotransformer;
- Added Ludlow 2X autotransformer; Added North Bloomfield 7K autotransformer;
- Added Tap Min/Max information for all LTCs in the CONVEX section;

**Maine**

- Added Bull Hill generator;
- Changed Maine Independence units heavy & light voltage schedules to 120 kV;
- Changed Rolls Wind and Stetson Wind units heavy & light loads voltage schedules to 118 kV;
- Removed Gulf Island KC1 capacitor; Added Larabee Road KC1, Starks KC1 & KC2 capacitors;
- Changed Wyman Hydro KC1 and KC2 capacitors' Available MVAr to 18;
- Added Albion Road KR1 & KR2 reactors; Added Albion Road T1 autotransformer;
- Replaced Keene Road T1 and Orrington T1 and T2 LTC voltage schedules with a general comment;

**New Hampshire**

- Added Groton Wind generator;
- Changed Scobie Pond R31 and R32 nominal voltage to 13.8 kV;

**NSTAR**

- Changed Dartmouth 3 heavy & light voltage schedules to 116 kV;
- Changed Fore River, Potter 2, Thomas A. Watson 1&2 light load voltage schedules to 117 kV;
- Changed Baker Street C1 & C2, and Lexington C1 Available MVAr to 54;
- Changed West Framingham C1 Available MVAr to 54.43;
- Added reactor ID's for all reactors in the NSTAR Transmission Reactors table;
- Removed Kingston 345A and 345B autotransformers;
- Replaced Woburn 345A LTC voltage schedule with a general comment;

**REMVEC**

- Changed Bear Swamp, Comerford, and Moore light and Peak load voltage schedules to 235 kV;
- Changed Brayton 1 & 2, Cleary CC, Cleary & Dighton Power, and Tiverton light load voltage schedules to 118 kV; Changed L'Energia and WMI Millbury light load voltage schedules to 117 kV;
- Changed Millenium GT & ST light & peak load voltage schedule to 118; Deleted Somerset Jet 2 since the unit is already retired;
- Added a general comment about the usage of the Sandy Pond capacitors/reactors under the capacitors and reactors tables; Added reactor ID's for all Sandy Pond reactors;

**VELCO**

- Changed Vermont Yankee's heavy & light loads voltage schedules to 357 kV;
- Added new Bennington C31, C32 capacitors;
- Added capacitor ID's for Highgate Converter Terminal capacitors;
- Added a general comment about the usage of Highgate Converter Terminal capacitors under the capacitors tables; Added New Haven R37 and Vernon VT R10 reactors;
- Changed West Rutland T1 & T2, and New Haven T1 & T2 autotransformers LTC voltage schedules to 117 kV;
Appendix C - Voltage and Reactive Surveys
## ISO New England Operating Procedure

**OP-12 - Voltage and Reactive Control, Appendix C**

### Contents

**CONVEX**
- Voltage & Reactive Surveys for Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Transmission, STATCOMs
- Voltage & Reactive Surveys for Autotransformers with LTCs

**Maine**
- Voltage & Reactive Surveys Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Transmission Static VAR Compensator
- Voltage & Reactive Surveys for Autotransformers with LTCs

**New Hampshire**
- Voltage & Reactive Surveys Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Autotransformers with LTCs

**NSTAR**
- Voltage & Reactive Surveys Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Autotransformers with LTCs

**REMVEC**
- Voltage & Reactive Surveys Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Autotransformers with LTCs

**VELCO**
- Voltage & Reactive Surveys Generators
- Transmission Capacitors
- Transmission Reactors
- Voltage & Reactive Surveys for Transmission, STATCOMs
- Voltage & Reactive Surveys for Autotransformers with LTCs

**OP 12 Appendix C Revision History**
## CONVEX Voltage & Reactive Surveys for Generators

**Survey Date:**

**Survey Time:**

**Survey Load Period: Heavy/Light (circle one)**

**Legend**

- **Sched** = Schedule
- **Max** = Maximum
- **Min** = Minimum

**MVar Out** = Gross Lagging based on NX-12D and operational data

**MVar In** = Gross Leading based on NX-12D and operational data

<table>
<thead>
<tr>
<th>Units</th>
<th>Operational Voltage Schedules Heavy Load Period</th>
<th>Operational Voltage Schedules Light Load Period</th>
<th>MVar Out @ S-SCC</th>
<th>MVar In @ Min Manual Load</th>
<th>Actual kV (Voltage)</th>
<th>MVar/Unit Status</th>
<th>AVR Status (On/Off)</th>
<th>Comment #</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. L. PIERCE</td>
<td>118 High 120 Low 117 High 119 Low 116</td>
<td></td>
<td>108</td>
<td></td>
<td>28 -15</td>
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</tr>
<tr>
<td>ALTRESCO</td>
<td>119 High 120 Low 117 High 119 Low 115</td>
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<td>163</td>
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<td>-24</td>
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<td>BERKSHIRE POWER</td>
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<tr>
<td>BRIDGEPORT ENERGY</td>
<td>118 High 120 Low 116 High 117 Low 116</td>
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<td>106</td>
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### CONVEX Voltage & Reactive Surveys for Generators

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**Survey Time:**

**Survey Load Period: Heavy/Light (circle one)**

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### CONVEX Voltage & Reactive Surveys for Generators

**Legend**

- **Sched** = Schedule
- **Max** = Maximum
- **Min** = Minimum

**MVar Out** = Gross Lagging based on NX-12D and operational data

**MVar In** = Gross Leading based on NX-12D and operational data

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### CONVEX Voltage & Reactive Surveys for Generators

**Survey Date:**

**Survey Time:**

**Survey Load Period: Heavy/Light**

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**Legend**

- **Sched = Schedule**
- **Max = Maximum**
- **Min = Minimum**

**MVar Out** = Gross Lagging based on NX-12D and operational data

**MVar In** = Gross Leading based on NX-12D and operational data

\(^1\) Sched = Schedule

\(^2\) Sched = Schedule

\(^3\) Based on NX-12D and operational data

\(^4\) Sched = Schedule
## CONVEX Voltage & Reactive Surveys for Generators

### Survey Date:
- **Survey Time:**
- **Survey Load Period:** Heavy/Light (circle one)

#### Legend
- **Sched =** Schedule
- **Max =** Maximum
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- **MVar Out =** Gross Lagging based on NX-12D and operational data
- **MVar In =** Gross Leading based on NX-12D and operational data

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### CONVEX Voltage & Reactive Surveys for Generators

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Note: Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

¹ Heavy load is from 0700-2200 Monday through Saturday except Holidays.
² Light load is all other hours.

Comments:
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*Sackett 1K capacitor is out of service until further notice*
## CONVEX Transmission Reactors

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### CONVEX Voltage & Reactive Surveys for Transmission, STATCOMs

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<th>Operational Voltage Schedules Light Load Period</th>
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1. Heavy load is from 0700-2200 Monday through Saturday except Holidays.
2. Light load is all other hours.
# CONVEX Voltage & Reactive Surveys for Autotransformers with LTCs

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<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
<th>Actual Voltage (kV)</th>
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## CONVEX Voltage & Reactive Surveys for Autotransformers with LTCs

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* Singer 1X is a GSU with tap changing options. It is LTC capable but is normally operated in manual.
**Maine Voltage & Reactive Surveys Generators**

<table>
<thead>
<tr>
<th>Units</th>
<th>Voltage Schedules Heavy Load Period</th>
<th>Voltage Schedules Light Load Period</th>
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## Maine Voltage & Reactive Surveys: Generators

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Units not listed will follow local voltage schedules in accordance with Local Control Center requirements or Interconnection Agreements.

1. Heavy load is from 0700-2200 Monday through Saturday except Holidays.
2. Light load is all other hours.
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# Maine Transmission Capacitors

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## Maine Transmission Reactors

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## Maine Voltage & Reactive Surveys for Transmission Static VAR Compensator

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* See M/LCC 9 and M/LCC 9 Attachment B for a detailed description of the voltage / reactive scheduling for the Chester SVC.
### Maine Voltage & Reactive Surveys for Autotransformers with LTCs

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* Transformer tap adjusted to maintain the appropriate voltage schedule based on prevailing system conditions

** This transformer LTC is run in manual when WEC is online.
## New Hampshire Voltage & Reactive Surveys for Generators

### Survey Date:

### Survey Time:

#### Survey Load Period: Heavy/Light (circle one)

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## New Hampshire Voltage & Reactive Surveys for Generators

### Survey Date:

### Survey Time:

### Survey Load Period: Heavy/Light (circle one)

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### Note:
Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

*Granite units CT1 & CT2 are located in the REMVEC Section*

**Error! Bookmark not defined.** Heavy load is from 0700-2200 Monday through Saturday except Holidays.

2 Light load is all other hours.

### Comments:

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## New Hampshire Transmission Capacitors

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<th>Substation Location</th>
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## New Hampshire Transmission Reactors

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<th>Reference Voltage (kV)</th>
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## New Hampshire Voltage & Reactive Surveys for Autotransformers with LTCs

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<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
<th>Surveyed Actual Voltage (kV)</th>
<th>Surveyed LTC Setting (Auto/Manual)</th>
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* This transformer LTC is run in manual when Merrimack units are on line
## NSTAR Voltage & Reactive Surveys - Generators

### Survey Results

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<th>Voltage Schedules Heavy Load Period</th>
<th>Voltage Schedules Light Load Period</th>
<th>Survey Load Period: Heavy/Light (circle one)</th>
<th>Survey Results</th>
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### NSTAR Voltage & Reactive Surveys Generators

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<td>Actual kV (Voltage)</td>
<td>MVAr/ Units Status</td>
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<td>MVAr Out @ Min Manual Load</td>
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<tr>
<th>Units</th>
<th>Survey Results</th>
<th>Comment #</th>
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<tr>
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<td>MVAr Out @ Min Manual Load</td>
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#### Voltage Schedules

**Legend**

- **Sched**: Schedule
- **Max**: Maximum
- **Min**: Minimum
- **MVAr Out**: Gross Lagging based on NX-12D and operational data
- **MVAr In**: Gross Leading based on NX-12D and operational data

#### Voltage Schedules

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<tr>
<th>Units</th>
<th>Voltage Schedules Heavy Load Period</th>
<th>Voltage Schedules Light Load Period</th>
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Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.

1. Heavy load is from 0700-2200 Monday through Saturday except Holidays.
2. Light load is all other hours.
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### NSTAR Transmission Capacitors

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### NSTAR Transmission Reactors

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### NSTAR Voltage & Reactive Surveys for Autotransformers with LTCs

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<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
<th>Surveyed LTC Setting (Auto/Manual)</th>
<th>Surveyed Actual Voltage (kV)</th>
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* Transformer tap adjusted to maintain the appropriate voltage schedule based on prevailing system conditions
### NSTAR Voltage & Reactive Surveys for Transmission, Static VAR Compensator

<table>
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<tr>
<th>Location</th>
<th>Voltage Schedules Heavy Load Period&lt;sup&gt;1&lt;/sup&gt;</th>
<th>Voltage Schedules Light Load Period&lt;sup&gt;2&lt;/sup&gt;</th>
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<tr>
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<tr>
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* Under normal operational conditions, the SVC will be operating with a zero (0) MVar output, ready to respond to faults in the network. During the first 2 seconds, the maximum MVar output is 225 MVar. After that, the MVar output is rapidly reduced to a maximum of 125 MVar, which can be sustained for up to 30 minutes.
## REMVEC

### REMVEC Voltage & Reactive Surveys Generators

<table>
<thead>
<tr>
<th>Survey Date:</th>
<th>Survey Time:</th>
<th>Survey Load Period: Heavy/Light (circle one)</th>
<th>Legend</th>
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<td>MVar Out = Gross Lagging based on NX-12D and operational data</td>
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<td>MVar In = Gross Leading based on NX-12D and operational data</td>
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## REMVEC Voltage & Reactive Surveys Generators

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<th>Voltage Schedules Heavy Load Period</th>
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<td>MVAR In @ Min Manual Load</td>
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### REMVEC Voltage & Reactive Surveys Generators

**Survey Date:**

**Survey Time:**

**Survey Load Period: Heavy/Light (circle one)**

<table>
<thead>
<tr>
<th>Legend</th>
<th>Voltage Schedules Heavy Load Period</th>
<th>Voltage Schedules Light Load Period</th>
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<tr>
<td>Min</td>
<td>Minimum</td>
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</tr>
<tr>
<td>MVar Out</td>
<td>Gross Lagging based on NX-12D and operational data</td>
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<tr>
<td>MVar In</td>
<td>Gross Leading based on NX-12D and operational data</td>
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<th>kV High</th>
<th>kV Low</th>
<th>kV Sched</th>
<th>kV High</th>
<th>kV Low</th>
<th>MVar Out @ S-SCC</th>
<th>Actual kV (Voltage)</th>
<th>MVar/Unit Status</th>
<th>AVR Status (On/Off)</th>
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<tbody>
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*Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.*

*The Granite Ridge ST unit is located in New Hampshire Section*

*Heavy load is from 0700-2200 Monday through Saturday except Holidays.*

*Light load is all other hours.*

### Comments:

- 
- 
- 
- 

**Revision 0 Effective Date:** draft
## REMVEC Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVAr</th>
<th>Reference Voltage (kV)</th>
<th>Actual Voltage (kV)</th>
<th>MVAr/ Capacitor status</th>
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<td>MONROE C22</td>
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*These capacitors are used to control Sandy Pond voltage when Phase II is ON with limited system voltage support. If Phase II is OFF, these capacitors can be used to support system voltages.
### REMVEC Transmission Reactors

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<th>Reference Voltage (kV)</th>
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<th>MVAr/ Reactor Status</th>
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<td>MONROE R14</td>
<td>1 @ -20.2</td>
<td></td>
<td>230</td>
<td></td>
</tr>
<tr>
<td>MONROE R21</td>
<td>1 @ -20.2</td>
<td></td>
<td>230</td>
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</tr>
<tr>
<td>MONROE R23</td>
<td>1 @ -20.2</td>
<td></td>
<td>230</td>
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<tr>
<td>SANDY POND V1-R11*</td>
<td>1@ -160</td>
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<td>345</td>
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<tr>
<td>SANDY POND V2-R21*</td>
<td>1@ -160</td>
<td></td>
<td>345</td>
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<tr>
<td>SANDY POND V2-R22*</td>
<td>1@ -160</td>
<td></td>
<td>345</td>
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</tr>
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</table>

*These reactors are used to control Sandy Pond voltage when Phase II is ON with limited system voltage support. If Phase II is OFF, these reactors can be used to support system voltages.
### REMVEC Voltage & Reactive Surveys for Autotransformers with LTCs

<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV</th>
<th>Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Schedul ed Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
<th>Surveyed Actual Voltage (kV)</th>
<th>Surveyed LTC Setting (Auto/Manual)</th>
<th>Survey Results</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

**Legend**
- **Sched** = Schedule
- **Max** = Maximum
- **Min** = Minimum
- **Auto** = Automatic

**Survey Date:**

**Survey Time:**

**Survey Load Period:** Heavy/Light (circle one)
### VELCO Voltage & Reactive Surveys Generators

<table>
<thead>
<tr>
<th>Units</th>
<th>Voltage Schedules Heavy Load Period</th>
<th>Voltage Schedules Light Load Period</th>
<th>Survey Load Period: Heavy/Light (circle one)</th>
<th>Survey Results</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tolerance Band</td>
<td>Tolerance Band</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>kV Sched</td>
<td>kV High</td>
<td>kV Low</td>
<td>MVar Out @ S-SCC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>kV Sched</td>
<td>kV High</td>
<td>MVar In @ Min Manual Load</td>
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<td></td>
<td></td>
<td>Actual kV (Voltage)</td>
<td>MVar/ Unit Status</td>
<td>AVR Status (On/Off)</td>
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<tr>
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<td></td>
<td>Manual Load</td>
<td></td>
<td></td>
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<tr>
<td>GRANITE SYNC COND</td>
<td>117.0</td>
<td>118.5</td>
<td>115.0</td>
<td>4 @ 25</td>
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<td></td>
<td>117.0</td>
<td>118.5</td>
<td>115.0</td>
<td>4 @ -12.5</td>
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<tr>
<td>VERMONT YANKEE</td>
<td>357</td>
<td>360</td>
<td>354</td>
<td>208</td>
</tr>
<tr>
<td></td>
<td>357</td>
<td>360</td>
<td>354</td>
<td>-50</td>
</tr>
</tbody>
</table>

*Units not listed will follow local voltage schedules in accordance with Local Control Center requirements.*

1 Heavy load is from 0700-2200 Monday through Saturday except Holidays.

2 Light load is all other hours.

**Comments:**

1. 
2. 
3. 
4. 

**Legend**

- Sched = Schedule
- Max = Maximum
- Min = Minimum
- MVar Out = Gross Lagging based on NX-12D and operational data
- MVar In = Gross Leading based on NX-12D and operational data
## VELCO Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVar</th>
<th>Reference Voltage (kV)</th>
<th>Actual kV (Voltage)</th>
<th>MVar/Capacitor status</th>
</tr>
</thead>
<tbody>
<tr>
<td>BENNINGTON C31</td>
<td>1 @ 12.42</td>
<td>115</td>
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<td></td>
</tr>
<tr>
<td>BENNINGTON C32</td>
<td>1 @ 12.42</td>
<td>115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BERLIN C87</td>
<td>1 @ 24.8</td>
<td>115</td>
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</tr>
<tr>
<td>COOLIDGE C91</td>
<td>1 @ 25.0</td>
<td>115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>COOLIDGE C92</td>
<td>1 @ 25.0</td>
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<td>ESSEX #1 C34</td>
<td>1 @ 24.3</td>
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<td>ESSEX C35;</td>
<td>1 @ 24.8</td>
<td>115</td>
<td></td>
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</tr>
<tr>
<td>ESSEX C36</td>
<td>1 @ 24.8</td>
<td>115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ESSEX C37</td>
<td>1 @ 24.8</td>
<td>115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ESSEX C38</td>
<td>1 @ 24.8</td>
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<tr>
<td>ESSEX C39</td>
<td>1 @ 24.8</td>
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<td></td>
</tr>
<tr>
<td>GEORGIA C41</td>
<td>1 @ 24.8</td>
<td>115</td>
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</tr>
<tr>
<td>HARTFORD C40</td>
<td>1 @ 25.0</td>
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</tr>
<tr>
<td>HIGHGATE CONVERTER TERMINAL S.22B*</td>
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<td>HIGHGATE CONVERTER TERMINAL S.23B*</td>
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<tr>
<td>HIGHGATE CONVERTER TERMINAL S.25B*</td>
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<td>HIGHGATE CONVERTER TERMINAL S.28B*</td>
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<td>HIGHGATE CONVERTER TERMINAL S.21B*</td>
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<td>HIGHGATE CONVERTER TERMINAL S.26B*</td>
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</tr>
<tr>
<td>GRANITE C61</td>
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<tr>
<td>GRANITE C62</td>
<td>1 @ 25.0</td>
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</tr>
<tr>
<td>GRANITE C66</td>
<td>1 @ 25.0</td>
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<td>LYNDONVILLE C21</td>
<td>1 @ 12.5</td>
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<tr>
<td>LYNDONVILLE C23</td>
<td>1 @ 12.5</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>MIDDLEBURY VB72</td>
<td>1 @ 22.9</td>
<td>115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NORTH RUTLAND C71</td>
<td>1 @ 24.8</td>
<td>115</td>
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### VELCO Transmission Capacitors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVAr</th>
<th>Reference Voltage (kV)</th>
<th>Actual kV (Voltage)</th>
<th>MVAr/ Capacitor status</th>
</tr>
</thead>
<tbody>
<tr>
<td>SANDBAR C82</td>
<td>1 @ 24.8</td>
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<tr>
<td>VERMONT YANKEE C50</td>
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<tr>
<td>VERMONT YANKEE C51</td>
<td>1 @ 15.0</td>
<td>115</td>
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<tr>
<td>VERMONT YANKEE C52</td>
<td>1 @ 30.0</td>
<td>115</td>
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<tr>
<td>WEST RUTLAND C45</td>
<td>1 @ 25.0</td>
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</tr>
<tr>
<td>WEST RUTLAND C46</td>
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<td></td>
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</tr>
<tr>
<td>WILLISTON C83</td>
<td>1 @ 25.2</td>
<td>115</td>
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</table>

*These capacitors are used to control Highgate voltage when the Highgate Converter is ON with limited system voltage support. If the Highgate Converter is OFF, 80 MVAr capacitors are available to provide voltage support when enabled by operators.*
## VELCO Transmission Reactors

<table>
<thead>
<tr>
<th>Substation Location</th>
<th>Available MVAr</th>
<th>Reference Voltage (kV)</th>
<th>Actual Voltage (kV)</th>
<th>MVAr/Reactor Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>COOLIDGE R41</td>
<td>1 @-34 Fixed -26 Variable</td>
<td>345</td>
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<tr>
<td>COOLIDGE R42</td>
<td>1 @-34 Fixed -26 Variable</td>
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<td>NEW HAVEN R37</td>
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<tr>
<td>VERNON_VT R10</td>
<td>1@-60</td>
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## VELCO Voltage & Reactive Surveys for Transmission, STATCOMs

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<thead>
<tr>
<th>Location</th>
<th>Survey Date:</th>
<th>Survey Time:</th>
<th>Tolerance Band</th>
<th>Tolerance Band</th>
<th>Available MVAr</th>
<th>Nominal Voltage (kV)</th>
<th>Actual Voltage (kV)</th>
<th>MVAr/STATCOM Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>ESSEX STATCOM</td>
<td></td>
<td></td>
<td>Voltage Schedules Heavy Load Period&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Voltage Schedules Light Load Period&lt;sup&gt;2&lt;/sup&gt;</td>
<td></td>
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<td></td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>kV High</td>
<td>kV Low</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Actual Voltage (kV)</td>
<td>Actual Voltage (kV)</td>
<td>MVAr/STATCOM Status</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ESSEX STATCOM</td>
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<td>119</td>
<td>115</td>
<td>117</td>
<td>119</td>
<td>115</td>
<td>-65 / +85</td>
<td>115</td>
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</table>
## VELCO Voltage & Reactive Surveys for Autotransformers with LTCs

<table>
<thead>
<tr>
<th>Substation Name</th>
<th>High Side kV/ Low Side kV</th>
<th>LTC Setting (Auto/Manual)</th>
<th>Scheduled Voltage (kV)</th>
<th>Max LTC Tap</th>
<th>Min LTC Tap</th>
<th>Voltage Control Bandwidth (kV)</th>
<th>Survey Results</th>
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<td>COOLIDGE XF</td>
<td>345/115</td>
<td>M</td>
<td>117</td>
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<td>N/A</td>
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</tr>
<tr>
<td>GRANITE T1</td>
<td>230/115</td>
<td>A</td>
<td>234</td>
<td>16</td>
<td>-16</td>
<td>237-230</td>
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<tr>
<td>GRANITE T2</td>
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<td>234</td>
<td>16</td>
<td>-16</td>
<td>237-230</td>
<td></td>
</tr>
<tr>
<td>WEST RUTLAND T1*</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7-114.1</td>
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</tr>
<tr>
<td>WEST RUTLAND T2*</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7-114.1</td>
<td></td>
</tr>
<tr>
<td>NEW HAVEN T1*</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7-114.1</td>
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</tr>
<tr>
<td>NEW HAVEN T2*</td>
<td>345/115</td>
<td>A</td>
<td>117</td>
<td>16</td>
<td>-16</td>
<td>118.7-114.1</td>
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</table>

*New Haven and West Rutland transformers operated in tandem
### OP-12, Appendix C Revision History

<table>
<thead>
<tr>
<th>Rev. No.</th>
<th>Date</th>
<th>Reason</th>
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<td>Rev 0</td>
<td>draft</td>
<td>Initial version.</td>
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Revision 0  Effective Date: draft

Hard Copy Is Uncontrolled

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Appendix D -
Voltage Schedule Annual Transmittal Form

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Voltage Schedule Annual Transmittal Form

[specify date]

Dear Lead Market Participant Contact:

This correspondence serves as the annual confirmation of your voltage control responsibilities as a Lead Market Participant (MP) of a Generator Asset in the ISO New England (ISO) Markets in accordance with ISO New England Operating Procedure No. 12, - Voltage and Reactive Control (OP-12). This correspondence also serves to meet the applicable requirements of the North American Electric Reliability Corporation (NERC) Reliability Standard VAR-001 - Voltage and Reactive Control for each Transmission Operator to specify a voltage or Reactive Power schedule to be maintained by each Generator. As described below, follow up action to this correspondence is required. This letter is being provided for: [Market Asset name], Asset # [Market Asset ID #].

**General responsibilities**

ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands (OP-14) requires that each Generator maintain an automatic voltage regulator (AVR) in service and regulating to the voltage schedule on all generating units comprising a Generator unless granted an exemption. Voltage control requirements are also contained in OP-12. These OP-14 and OP-12 requirements pertaining to voltage and reactive control are consistent with applicable requirements in NERC Reliability Standard VAR-002. Any Generators exempted from this requirement are noted in Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages, Attachment A - Generators Exempted from AVR Requirements (M/LCC 8A). Voltage schedules and limits for NERC registered and/or transmission (69 kV or higher) connected Generators that can control transmission voltage at key transmission stations that have not been exempted are specified by ISO in OP-12, Appendix B - Voltage & Reactive Schedules (OP-12B). A Generator Asset in the ISO Markets must either hold a voltage schedule or receive an exemption. The voltage schedule can either be a transmission voltage schedule or a voltage schedule at less than transmission levels (< 69 kV).
Specific voltage requirements for your Generator Asset

Our records indicate that your voltage control requirements are as shown in one of the three options designated below.

OPTION A – Voltage control for transmission (69 kV and above)

- The asset has a voltage schedule in OP-12B

<table>
<thead>
<tr>
<th>Schedule (kV)</th>
<th>Schedule max (kV)</th>
<th>Schedule min (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Schedule (kV)</th>
<th>Schedule max (kV)</th>
<th>Schedule min (kV)</th>
</tr>
</thead>
</table>

OPTION B – Voltage control for below transmission (less than 69 kV)

- The Generator Asset has a voltage schedule at non-transmission levels (not listed in OP-12B)

<table>
<thead>
<tr>
<th>Schedule (kV)</th>
<th>Schedule max (kV)</th>
<th>Schedule min (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Schedule (kV)</th>
<th>Schedule max (kV)</th>
<th>Schedule min (kV)</th>
</tr>
</thead>
</table>

OPTION C - Exemption

- The Generator Asset has a voltage schedule at non-transmission levels (not listed in OP-12B)

Follow up action required

Depending on the voltage requirements specified above for your Generator Asset, the following action is required.

If your voltage requirements are specified in OPTION A:

Any Generator Asset with a voltage schedule listed in OP-12B (i.e., “OPTION A”) must follow the above noted transmission voltage schedule, within the noted voltage schedule maximum and minimum values, as described in OP-12. Within 30 days of receiving this correspondence, please perform the tasks listed below and then “reply to all” to the email you received containing this correspondence to confirm that these tasks have been completed:

1. Provide these voltage schedules and requirements information to the entity that controls or operates (either remotely or locally) the voltage control equipment for this Generator Asset

---

1 Heavy load is from 0700-2200 Monday through Saturday except Holidays.

2 Light load is all other hours
2. Confirm that this entity has incorporated these voltage schedules and requirements information into their operating procedures.

3. Confirm these voltage schedules with those submitted in the Generator NX-12D form and if they are different, update the NX-12D form with these voltage schedules and submit the new form to ISO.

4. Indicate in your confirmation email whether the entity that controls or operates (either remotely or locally) the voltage control equipment for this Generator Asset has high side voltage visibility.

If your voltage requirements are specified in OPTION B:

Any generation asset with a voltage schedule at levels below transmission levels (i.e., “OPTION B”) is asked to confirm the noted voltage schedule and voltage schedule maximum and minimum values. Per OP-14, ISO and the LCCs may revise the noted voltage schedule, as necessary. **Within 30 days of receiving this correspondence**, please perform the tasks listed below and then “reply to all” to the email you received containing this correspondence to confirm that these tasks have been completed:

1. Confirm that the voltage schedule maximum and minimum values are acceptable or, if deemed unacceptable, provide an explanation.

2. If the voltage schedule maximum and minimum values are confirmed to be acceptable, then
   a. Provide these voltage schedules and requirements information to the entity that controls or operates (either remotely or locally) the voltage control equipment for this Generator Asset.
   b. Confirm that this entity has incorporated these voltage schedules and requirements information into their operating procedures.

3. Confirm these voltage schedules with those submitted in the Generator NX-12D form and if they are different, update the NX-12D form with these voltage schedules and submit the new form to ISO.

4. Indicate whether the entity has high side voltage visibility.

If your voltage requirements are specified in OPTION C:

Any generation asset with an exemption in M/LCC-8, Attachment A (i.e., “OPTION C”) need not follow a voltage schedule, nor have its AVR in voltage control mode; these assets instead need to operate the Generator Asset in the agreed upon reactive performance mode (i.e. constant power factor or constant reactive output) to preclude adverse reliability impacts. **Within 30 days of receiving this correspondence**, please perform the tasks listed below and then “reply to all” to the email you received containing this correspondence to confirm that these tasks have been completed:

1. Provide a description of your reactive controls and operation in lieu of maintaining a voltage schedule through use of your AVR or its equivalent.
Questions?

Questions regarding the voltage schedule information in this letter may be forwarded to me and the below listed e-mail address for resolution:
vtfcontact@iso-ne.com

Sincerely,
[LCC contact person name]
[LCC name]

Cc:
Designated Entity Operations Management Contact
vtfcontact@iso-ne.com

OP-12, Appendix D Revision History

Document History:

<table>
<thead>
<tr>
<th>Rev. No.</th>
<th>Date</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rev 0</td>
<td>draft</td>
<td>Initial version</td>
</tr>
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</table>
Summary of ISO New England Board and Committee Meetings

December 6, 2013 Participants Committee Meeting

Since the last update, the Board met on November 7 in Boston. The Audit and Finance Committee, the Compensation and Human Resources Committee and the Markets Committee each met on November 21, and the Board met on November 22 in Holyoke.

On November 7, the Board received reports from the standing committees, including the committees’ risk assessments. After reviewing a summary of stakeholder comments from the System Planning and Reliability Committee, the Board approved the 2013 Regional System Plan. The Board then prepared for sector meetings with NEPOOL and reviewed topics proposed by stakeholders for discussion. Finally, the Board met in executive session to discuss the pending litigation and upcoming auction in the Forward Capacity Market.

The Audit and Finance Committee met on November 21 and reviewed compliance issues, including the results of the annual process of ensuring employees are in compliance with the Code of Conduct. The Committee met with representatives of KPMG, the Company’s external auditors, to discuss preliminary results of the 2013 SOC1/SSAE 16 review. KPMG also provided an overview of work plans for the financial statements audit. The Committee met with the auditors in executive session. The internal auditor gave an update on recent activities and provided the work plan for 2014. The Committee also reviewed an update on the investment of pension and post-retirement plan assets. The Committee reviewed current budget performance, and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. The Committee discussed the quarterly update on interest rates and decided to maintain existing variable rates and continue to monitor rates on a quarterly basis and evaluate risk tolerance for interest rate changes.

The Compensation and Human Resources Committee convened on November 21. The Committee reviewed and approved the payment of annual performance awards for employees retiring in 2013. The Committee also discussed the process for approving corporate goals for 2014.
The Markets Committee met on November 21 and received reports from the internal and external market monitors, and the COO’s report on reliability costs. The Committee discussed the mechanics of reserve market pricing and the interaction of energy and reserve prices. The Committee discussed the reasons for the energy price spikes during October and the appropriate frequency of price volatility. There was a general conversation concerning the Installed Capacity Requirement and the large amount of generator outages during July. The Committee also noted the recent increase in the capacity market reconfiguration auction clearing price. The Committee discussed recent developments concerning the upcoming Forward Capacity Market annual auction and the FCM performance incentives proposal. The Committee was provided with an update on recent activities involving the NEPOOL Markets Committee and its review of the FCM PI proposal and series of amendments concerning performance exemptions. Finally, the Committee discussed the likely impact of natural gas pipeline constraints on New England’s electricity prices during the winter months.

The Board of Directors met on November 22 with the Federal Energy Regulatory Commission’s Director of the Office of Energy Infrastructure, Joseph H. McClelland, to discuss cyber security matters.
NEPOOL Participants Committee Report

December 2013

Vamsi Chadalavada
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER
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  - Forward Capacity Market  
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs  
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  - Operable Capacity Analysis – Fall 2013 and Winter 2013/2014  
  - Operable Capacity Analysis – Appendix
Highlights

• Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  – November natural gas prices over the period were 51% higher, while oil prices were 1.0% lower than October 2013 average values
  – Average RT Hub Locational Marginal Prices (LMPs) over the period were 25% higher than October 2013 averages

• Average November 2013 natural gas prices and RT Hub LMPs were down 15% and 21%, respectively, from November 2012 averages.

• Winter 2013-14 Reliability Program Dual-Fuel Unit Fuel-Switch Testing
  – As of December 3, 2013, 13 out of 14 dual-fuel units participating in the Program have successfully tested their switching capability
  – As of December 3, 2013, 11 of the 14 units have settled, at a cost totaling $1.4M

*All data through November 25th unless noted.*
Highlights, cont.

• Daily Net Commitment Period Compensation (NCPC)*
  – November payments totaled $5.3M, up $2.9M from October
  – First Contingency payments totaled $3.8M, up $2.1M from October**
    • $3.5M paid to internal resources, up $1.9M from October
      – $1.5M charged to DALO, $2.1M to RT Deviations
    • $287K paid to resources at external locations, up $251K from October
      – $263K charged to DALO at external locations, $24K to RT Deviations
  – Second Contingency payments totaled $253K, down $208K from the
    October total of $461K
  – Voltage payments totaled $1.2M, up $1.1M from October
  – Distribution payments totaled $0, down $111K from October
  – NCPC payments over the period as percent of Energy Market value were
    1.4%

*Total includes NCPC payments to eligible resources at external locations.
**Includes $576K of the $1.4M incurred in dual fuel unit testing (as part of the winter reliability program)
Highlights, cont.

• The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for the week beginning January 18th.

• Starting December 9, the ISO will publish hourly forecasted demand for the current day and next two days by reliability region/load zone
  – Forecast will be published daily by 8 AM
Highlights, cont.

Winter Reliability Program Update
Fuel Survey Update as of 12/2

• 56 Generators are participating in the Winter Fuel Procurement Program. All have submitted Monthly Fuel Inventory Surveys and are being verified
  – 43 generators have met or exceeded their required fuel inventory for 12/1
  – 13 are still in the process of being verified
A Few Operational Observations

• The amount of load that cleared in the Day-Ahead market has increased in contrast to earlier this year and past years
  – In October and November 2013, the average load that cleared (all hours) in the Day-Ahead market was 94.9% and 94.7% of forecast load
  – In October and November 2013, the average load that cleared (peak hours) in the Day-Ahead market was 96.6% and 95.9% of forecast load

• The Replacement Reserve trigger continues to work effectively for its intended purpose of pricing operator reliability actions
  – Between October 1 and December 1 2013, there were 26 hours during which the Replacement Reserve RCPF was violated for at least one interval; and 10 hours where the Replacement Reserve RCPF was binding
A Few Operational Observations, cont.

• As a reminder, when resources that are generally needed for system reliability do not clear the day ahead market, they may be committed in the RAA process which contributes to uplift.

• Some resources in NEMA have changed offer parameters (following consultation with the ISO Internal Market Monitor) that may lead to uplift for second contingency protection.
Highlights, cont.

• The 2013 Regional System Plan was approved by the ISO Board of Directors on November 8

• A draft interim photovoltaic forecast and interconnection issues will be discussed with the Distributed Generation Forecast Working Group on December 16

• ICF will report on Phase II of the Natural Gas Study at the December 18 Planning Advisory Committee meeting

• Results of the reliability determination analysis for a number of non-price retirement requests will be presented at the December 19 Reliability Committee meeting
Highlights, cont.
Forward Capacity Market Update

• CCP #8 (2017-2018)
  – FERC filing made on November 25 to address the insufficient competition gap in the market rules as well as modify the administrative price for existing capacity resources
  – Non-price retirement requests for Vermont Yankee have been approved and other requests are under study. Study results will be presented at the December 19 RC meeting.
  – Auction to commence on February 3

• CCP #9 (2018-2019)
  – Capacity zones stakeholder meetings ongoing with RC, MC and TC
  – Market rule language has been presented for Section 12 and Attachment K and will seek a vote at the December 19 RC meeting
SYSTEM OPERATIONS
# System Operations

<table>
<thead>
<tr>
<th>Weather Patterns</th>
<th>Boston</th>
<th>Hartford</th>
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</thead>
<tbody>
<tr>
<td>Temperature – Below Average ( -2.8 )</td>
<td>Max 72, Min 18</td>
<td>Temperature – Below Average ( -3.3 )</td>
</tr>
<tr>
<td>Precipitation 2.69” (Liquid) Below Average</td>
<td>Max 68, Min 13</td>
<td>Precipitation 4.11” (Liquid) – Average</td>
</tr>
<tr>
<td>Normal 3.98”</td>
<td>Normal = 4.06”</td>
<td></td>
</tr>
</tbody>
</table>

| Peak Load: | 19,175 MW | November 25, 2013 | 18:00 |

| MLCC2: | 11/12/13 | 16:15 – 16:38 | In New Hampshire Only. | Due to computer failure |

| OP-4 | None |

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<th>NPCC Simultaneous Activation of Reserve Events:</th>
<th>ISO-NE</th>
<th>800 MW</th>
</tr>
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<tr>
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<td>ISO-NE</td>
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<tr>
<td>11/09/2013</td>
<td>ISO-NE</td>
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<td>11/11/2013</td>
<td>IESO</td>
<td>840 MW</td>
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<td>11/21/2013</td>
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<td>IESO</td>
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<td>11/30/2013</td>
<td>NYISO</td>
<td>550 MW</td>
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# System Operations

## Minimum Generation Warnings & Events:

<table>
<thead>
<tr>
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<th>Date</th>
<th>Duration</th>
<th>Action Details</th>
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<tr>
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<td></td>
<td>Start-14:00, Expired-17:00 Interchange Cuts &amp; SS Denied</td>
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<td>11/03/13 – 11/04/13</td>
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<td>11/12/13</td>
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<td>Start-03:00 Expired - 06:00 Interchange Cuts &amp; SS Denied</td>
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<td>Minimum Generation Event</td>
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<td>Start-04:00, Expired-06:00 Interchange Cuts &amp; SS Denied</td>
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# System Operations

Minimum Generation Warnings & Events:

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<td>11/14/13</td>
<td>Start- 23:00, Expired-23:59 Interchange Cuts Only</td>
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<td>Minimum Generation Warning</td>
<td>11/15/13</td>
<td>Start – 03:00, Expired – 06:00 Interchange Cuts Only</td>
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<td>11/18/13</td>
<td>Start-00:01 Expired - 06:00 Interchange Cuts Only</td>
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<td>11/23/13</td>
<td>Start-04:00 Expired-09:00 Interchange Cuts Only</td>
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<td>11/23/13</td>
<td>Start-13:00 Expired-17:00 SS Denied Only</td>
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## System Operations

### Minimum Generation Warnings & Events:

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2013 System Operations – Load Forecast Accuracy

All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published by 1000 on day before Operating Day

<table>
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<tr>
<th></th>
<th>J</th>
<th>F</th>
<th>M</th>
<th>A</th>
<th>M</th>
<th>J</th>
<th>J</th>
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<th>O</th>
<th>N</th>
<th>D</th>
<th>Avg</th>
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<td>Mo Avg</td>
<td>1.45</td>
<td>1.64</td>
<td>1.17</td>
<td>1.22</td>
<td>1.56</td>
<td>2.26</td>
<td>2.40</td>
<td>1.78</td>
<td>1.41</td>
<td>0.94</td>
<td>1.52</td>
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<tr>
<td>Day Max</td>
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<td>9.45</td>
<td>2.45</td>
<td>3.32</td>
<td>6.07</td>
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<td>5.70</td>
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<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
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<tr>
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<td>1.17</td>
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<td>1.41</td>
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<td>1.36</td>
<td>1.36</td>
<td>1.36</td>
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Summer Goal - 2.6%, Rest of Year Goal - 1.5%
Summer consists of June, July & August

Rest of Year Goal < 1.5%
Summer Goal < 2.6%
Peak Hours
Monthly Average, Daily Maximum and Minimum
Based on forecast published by 1000 on day before Operating Day

<table>
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<th>M</th>
<th>A</th>
<th>M</th>
<th>J</th>
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<th>O</th>
<th>N</th>
<th>D</th>
<th>Avg</th>
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<tr>
<td>Mo Avg</td>
<td>1.30</td>
<td>1.15</td>
<td>1.13</td>
<td>1.18</td>
<td>1.92</td>
<td>2.90</td>
<td>3.06</td>
<td>2.34</td>
<td>1.48</td>
<td>0.95</td>
<td>1.60</td>
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<td>0.01</td>
<td>0.06</td>
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<td>0.09</td>
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<td>1.50</td>
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<tr>
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Summer Goal - 2.6%, Rest of Year Goal - 1.5%
Summer consists of June, July & August

Rest of Year Goal < 1.5%
Summer Goal < 2.6%
2013 System Operations - Load Forecast Accuracy

Percent of Hours Actual Load Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

Target = 50%
Plus/Minus 5%

Percent of hours that the actual load was above versus below the forecast

<table>
<thead>
<tr>
<th></th>
<th>Above %</th>
<th>Below %</th>
<th>Avg Above</th>
<th>Avg Below</th>
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<tr>
<td>J</td>
<td>53.2</td>
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<td>M</td>
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<td>S</td>
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<td>54.1</td>
<td>-40.4</td>
</tr>
</tbody>
</table>
2013 System Operations - Load Forecast Accuracy

Deviation of Actual Load from Forecasted Load Year to Date 2013

Mega Watts

-3500 -2500 -1500 -500 500 1500 2500 3500

Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec AVG

Legend:
- Average Above
- Average Below
- Max Above
- Max Below

Actual load above forecast
Actual load below forecast
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Current month’s data may be preliminary. Weather normalized NEL may be reported on a one-month lag.
Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load

Weather Normalized Seasonal Peaks

Winter beginning in year displayed

* F – designates forecasted values, which are updated in April/May of the following year.
MARKET OPERATIONS
Underlying natural gas data furnished by:

Average price difference over this period (DA-RT): $-2.65
Average price difference over this period ABS(DA-RT): $9.85
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%

Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOE's Energy Information Administration
DA LMPs Average by Zone & Hub, November 2013

<table>
<thead>
<tr>
<th>Hub</th>
<th>ME - Maine</th>
<th>NH - New Hampshire</th>
<th>VT - Vermont</th>
<th>CT - Connecticut</th>
<th>RI - Rhode Island</th>
<th>SEMA - Southeastern Massachusetts</th>
<th>WCMA - Western/Central Massachusetts</th>
<th>NEMA - Northeastern Massachusetts</th>
</tr>
</thead>
<tbody>
<tr>
<td>LMP</td>
<td>(1.6%)</td>
<td>0.4%</td>
<td>(1.8%)</td>
<td>(1.0%)</td>
<td>0.4%</td>
<td>1.3%</td>
<td>0.4%</td>
<td>0.6%</td>
</tr>
</tbody>
</table>
RT LMPs Average by Zone & Hub, November 2013

[Bar chart showing LMPs for different zones and hubs with values from $0 to $200]
Components of Cleared DA Supply and Demand – Last Three Months

Supply

Demand

Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load
Components of RT Supply and Demand – Last Three Months

Supply

<table>
<thead>
<tr>
<th>Avg Hourly MW</th>
<th>SEP2013</th>
<th>OCT2013</th>
<th>NOV2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen</td>
<td>15,000</td>
<td>12,500</td>
<td>15,000</td>
</tr>
<tr>
<td>Imports</td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
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Demand

<table>
<thead>
<tr>
<th>Avg Hourly MW</th>
<th>SEP2013</th>
<th>OCT2013</th>
<th>NOV2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>15,000</td>
<td>12,500</td>
<td>15,000</td>
</tr>
<tr>
<td>Exports</td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
</tr>
<tr>
<td>DA Fcst Load</td>
<td>2,500</td>
<td>2,500</td>
<td>2,500</td>
</tr>
</tbody>
</table>

- DA Fcst Load
Hourly DA LMPs, November 1-25, 2013
Hourly RT LMPs, November 1-25, 2013

Tight capacity with binding reserve constraints over the evening pickup preceded by the loss of a large generator.

Tight capacity with binding reserve constraints, loads running over forecast, and reduced net imports during morning pickup.
System Unit Availability

<table>
<thead>
<tr>
<th>Year</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>89</td>
<td>87</td>
<td>85</td>
<td>76</td>
<td>81</td>
<td>90</td>
<td>90</td>
<td>92</td>
<td>88</td>
<td>80</td>
<td>81</td>
<td></td>
<td>85</td>
</tr>
<tr>
<td>2012</td>
<td>93</td>
<td>92</td>
<td>88</td>
<td>75</td>
<td>83</td>
<td>93</td>
<td>95</td>
<td>95</td>
<td>91</td>
<td>76</td>
<td>80</td>
<td>89</td>
<td>88</td>
</tr>
<tr>
<td>2011</td>
<td>92</td>
<td>89</td>
<td>83</td>
<td>74</td>
<td>76</td>
<td>95</td>
<td>96</td>
<td>95</td>
<td>90</td>
<td>73</td>
<td>83</td>
<td>89</td>
<td>86</td>
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<tr>
<td>2010</td>
<td>91</td>
<td>93</td>
<td>90</td>
<td>83</td>
<td>74</td>
<td>93</td>
<td>93</td>
<td>93</td>
<td>86</td>
<td>77</td>
<td>81</td>
<td>91</td>
<td>87</td>
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</table>

Data as of 12/2/13
BACK-UP DETAIL
LOAD RESPONSE
### Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2013

<table>
<thead>
<tr>
<th>Load Zone</th>
<th>RTDR*</th>
<th>RTEG**</th>
<th>On Peak</th>
<th>Seasonal Peak</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>ME</td>
<td>137.04</td>
<td>7.22</td>
<td>88.09</td>
<td>0.00</td>
<td>232.36</td>
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<tr>
<td>NH</td>
<td>3.43</td>
<td>11.51</td>
<td>64.72</td>
<td>0.00</td>
<td>79.67</td>
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<tr>
<td>VT</td>
<td>27.97</td>
<td>2.10</td>
<td>88.86</td>
<td>0.00</td>
<td>118.93</td>
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<tr>
<td>CT</td>
<td>56.28</td>
<td>55.37</td>
<td>80.89</td>
<td>299.33</td>
<td>491.86</td>
</tr>
<tr>
<td>RI</td>
<td>11.03</td>
<td>6.62</td>
<td>75.38</td>
<td>0.00</td>
<td>93.03</td>
</tr>
<tr>
<td>SEMA</td>
<td>8.16</td>
<td>10.73</td>
<td>111.62</td>
<td>0.00</td>
<td>130.52</td>
</tr>
<tr>
<td>WCMA</td>
<td>20.64</td>
<td>14.05</td>
<td>101.65</td>
<td>28.69</td>
<td>165.03</td>
</tr>
<tr>
<td>NEMA</td>
<td>3.87</td>
<td>19.10</td>
<td>200.67</td>
<td>0.00</td>
<td>223.64</td>
</tr>
<tr>
<td>Total</td>
<td>268.42</td>
<td>126.72</td>
<td>811.88</td>
<td>328.02</td>
<td>1,535.03</td>
</tr>
</tbody>
</table>

* Real Time Demand Response
** Real Time Emergency Generation

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.
NEW GENERATION
New Generation Update
Based on 11/27/13 Interim Queue Update

• No new projects have applied for interconnection study since the last update
• Two projects withdrew from the Queue and one went commercial, resulting in a net decrease in new generation projects of 97 MW
• In total, 49 generation projects are currently being tracked by the ISO, totaling 5,100 MW
Actual and Projected Annual Capacity Additions
By Supply Fuel Type and Demand Resource Type

- 2013 values include the 51 MW of generation that has gone commercial in 2013
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

### Table

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Total MW</th>
<th>% of Total*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Response - Passive</td>
<td>225</td>
<td>188</td>
<td>157</td>
<td>-12</td>
<td>0</td>
<td>558</td>
<td>11.1</td>
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<tr>
<td>Demand Response - Active</td>
<td>169</td>
<td>19</td>
<td>3</td>
<td>-868</td>
<td>0</td>
<td>-677</td>
<td>-13.5</td>
</tr>
<tr>
<td>Wind &amp; Other Renewables</td>
<td>142</td>
<td>150</td>
<td>260</td>
<td>1,327</td>
<td>485</td>
<td>2,364</td>
<td>47.1</td>
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<tr>
<td>Oil</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>14</td>
<td>14</td>
<td>0.3</td>
</tr>
<tr>
<td>Natural Gas/Oil</td>
<td>0</td>
<td>19</td>
<td>0</td>
<td>1,461</td>
<td>748</td>
<td>2,228</td>
<td>44.4</td>
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<tr>
<td>Natural Gas</td>
<td>10</td>
<td>41</td>
<td>0</td>
<td>0</td>
<td>482</td>
<td>533</td>
<td>10.6</td>
</tr>
<tr>
<td>Totals</td>
<td>546</td>
<td>417</td>
<td>420</td>
<td>1,908</td>
<td>1,729</td>
<td>5,020</td>
<td>100.0</td>
</tr>
</tbody>
</table>

* Sum may not equal 100% due to rounding
Actual and Projected Annual Generator Capacity Additions

By State

- 2013 values include the 51 MW of generation that has gone commercial in 2013

<table>
<thead>
<tr>
<th>State</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Total MW</th>
<th>% of Total*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vermont</td>
<td>0</td>
<td>30</td>
<td>97</td>
<td>33</td>
<td>20</td>
<td>180</td>
<td>3.5</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>28</td>
<td>0</td>
<td>0</td>
<td>29</td>
<td>0</td>
<td>57</td>
<td>1.1</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>76</td>
<td>30</td>
<td>51</td>
<td>0</td>
<td>74</td>
<td>231</td>
<td>4.5</td>
</tr>
<tr>
<td>Maine</td>
<td>10</td>
<td>82</td>
<td>107</td>
<td>716</td>
<td>391</td>
<td>1,306</td>
<td>25.4</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>0</td>
<td>53</td>
<td>5</td>
<td>1,265</td>
<td>762</td>
<td>2,085</td>
<td>40.6</td>
</tr>
<tr>
<td>Connecticut</td>
<td>38</td>
<td>15</td>
<td>0</td>
<td>745</td>
<td>482</td>
<td>1,280</td>
<td>24.9</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>152</strong></td>
<td><strong>210</strong></td>
<td><strong>260</strong></td>
<td><strong>2,788</strong></td>
<td><strong>1,729</strong></td>
<td><strong>5,139</strong></td>
<td><strong>100.0</strong></td>
</tr>
</tbody>
</table>

* Sum may not equal 100% due to rounding
## New Generation Projection

### By Fuel Type

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Total</th>
<th>Green</th>
<th>Yellow</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No. of Projects</td>
<td>Capacity (MW)</td>
<td>No. of Projects</td>
</tr>
<tr>
<td>Biomass/Wood Waste</td>
<td>5</td>
<td>213</td>
<td>2</td>
</tr>
<tr>
<td>Hydro</td>
<td>5</td>
<td>68</td>
<td>0</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>3</td>
<td>518</td>
<td>1</td>
</tr>
<tr>
<td>Natural Gas/Oil</td>
<td>7</td>
<td>2,228</td>
<td>0</td>
</tr>
<tr>
<td>Oil</td>
<td>1</td>
<td>14</td>
<td>0</td>
</tr>
<tr>
<td>Solar</td>
<td>3</td>
<td>16</td>
<td>2</td>
</tr>
<tr>
<td>Wind</td>
<td>25</td>
<td>2,031</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>49</td>
<td>5,088</td>
<td>8</td>
</tr>
</tbody>
</table>

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications
# New Generation Projection

## By Operating Type

<table>
<thead>
<tr>
<th>Operating Type</th>
<th>Total</th>
<th>Green</th>
<th>Yellow</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No. of Projects</td>
<td>Capacity (MW)</td>
<td>No. of Projects</td>
</tr>
<tr>
<td>Baseload</td>
<td>6</td>
<td>228</td>
<td>3</td>
</tr>
<tr>
<td>Intermediate</td>
<td>10</td>
<td>2,322</td>
<td>0</td>
</tr>
<tr>
<td>Peaker</td>
<td>8</td>
<td>507</td>
<td>2</td>
</tr>
<tr>
<td>Wind Turbine</td>
<td>25</td>
<td>2,031</td>
<td>3</td>
</tr>
<tr>
<td>Total</td>
<td>49</td>
<td>5,088</td>
<td>8</td>
</tr>
</tbody>
</table>

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications
## New Generation Projection

*By Operating Type and Fuel Type*

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Total</th>
<th>Baseload</th>
<th>Intermediate</th>
<th>Peaker</th>
<th>Wind Turbine</th>
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<tbody>
<tr>
<td></td>
<td>No. of Projects</td>
<td>Capacity (MW)</td>
<td>No. of Projects</td>
<td>Capacity (MW)</td>
<td>No. of Projects</td>
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<tr>
<td>Biomass/Wood Waste</td>
<td>5</td>
<td>213</td>
<td>5</td>
<td>213</td>
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</tr>
<tr>
<td>Hydro</td>
<td>5</td>
<td>68</td>
<td>0</td>
<td>0</td>
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<td>Landfill Gas</td>
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<td>0</td>
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<tr>
<td>Natural Gas</td>
<td>3</td>
<td>518</td>
<td>1</td>
<td>15</td>
<td>2</td>
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<tr>
<td>Natural Gas/Oil</td>
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<td>0</td>
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<tr>
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<td>14</td>
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<td>0</td>
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<tr>
<td>Solar</td>
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<td>16</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Wind</td>
<td>25</td>
<td>2,031</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>49</td>
<td>5,088</td>
<td>6</td>
<td>228</td>
<td>10</td>
</tr>
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</table>
FORWARD CAPACITY MARKET
## Capacity Supply Obligation FCA 4

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA 4</th>
<th>Proration</th>
<th>Annual Bilateral for ARA 2</th>
<th>Period 1</th>
<th>ARA 2</th>
<th>Annual Bilateral for ARA 2</th>
<th>Period 2</th>
<th>ARA 3</th>
<th>Annual Bilateral 3 Period</th>
<th>ARA 3</th>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
</tr>
<tr>
<td>Demand</td>
<td>Active Demand</td>
<td>2,051.536</td>
<td>1,860.060</td>
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<td>1,681.032</td>
<td>-179.028</td>
<td>1,482.357</td>
<td>-198.675</td>
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<td>-115.000</td>
<td>1,021.146</td>
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<tr>
<td></td>
<td>Passive Demand</td>
<td>1,297.906</td>
<td>1,154.626</td>
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<td>1,135.705</td>
<td>-18.921</td>
<td>1,163.465</td>
<td>27.760</td>
<td>1,163.465</td>
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<td>2,645.822</td>
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<td>2,530.822</td>
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<td>972.075</td>
<td>-6.997</td>
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<td>-114.189</td>
<td>865.064</td>
<td>7.178</td>
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<td>1,726.449</td>
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<td>-330.191</td>
<td>1,396.258</td>
<td>0.000</td>
<td>1,296.258</td>
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</table>

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.
## Capacity Supply Obligation FCA 5

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA 4</th>
<th>Proration</th>
<th>Annual Bilateral for ARA 2</th>
<th>ARA 2</th>
<th>Annual Bilateral for ARA 3</th>
<th>ARA 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
<td>MW</td>
</tr>
<tr>
<td><strong>CSO</strong></td>
<td><strong>CSO</strong></td>
<td></td>
<td><strong>Change</strong></td>
<td><strong>ARA 2</strong></td>
<td><strong>Change</strong></td>
<td><strong>CSO</strong></td>
<td><strong>Change</strong></td>
</tr>
<tr>
<td>Demand</td>
<td><strong>Active Demand</strong></td>
<td>2,104.141</td>
<td>2,001.126</td>
<td>-103.015</td>
<td>1,385.670</td>
<td>-615.456</td>
<td>1,074.461</td>
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<tr>
<td></td>
<td><strong>Passive Demand</strong></td>
<td>1,485.713</td>
<td>1,397.586</td>
<td>-88.127</td>
<td>1,345.283</td>
<td>-52.303</td>
<td>1,348.593</td>
</tr>
<tr>
<td>Generator</td>
<td><strong>Non-Intermittent</strong></td>
<td>30,558.220</td>
<td>28,337.481</td>
<td>-2,220.739</td>
<td>27,917.690</td>
<td>-419.791</td>
<td>28,364.588</td>
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<tr>
<td></td>
<td><strong>Intermittent</strong></td>
<td>880.737</td>
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<td>-39.16</td>
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</table>

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.
### Capacity Supply Obligation FCA 6

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<tr>
<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA</th>
<th>Proration</th>
<th>Annual Bilateral for ARA 1</th>
<th>ARA 1</th>
<th>Annual Bilateral for ARA 2</th>
<th>ARA 2</th>
<th>Annual Bilateral for ARA 3</th>
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* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.
## Capacity Supply Obligation FCA 7

<table>
<thead>
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<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA</th>
<th>Proration</th>
<th>Annual Bilateral for ARA 1</th>
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</table>

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.
RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS
What are Daily NCPC Payments?

• “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day.

• Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area.
<table>
<thead>
<tr>
<th>Definitions</th>
<th>1st Contingency NCPC Payments</th>
<th>Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally.</th>
</tr>
</thead>
<tbody>
<tr>
<td>2nd Contingency NCPC Payments</td>
<td>Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR).</td>
<td></td>
</tr>
<tr>
<td>Voltage NCPC Payments</td>
<td>Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations.</td>
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</tr>
<tr>
<td>Distribution NCPC Payments</td>
<td>Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software.</td>
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<tr>
<td>Delisted Units</td>
<td>Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market.</td>
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</tr>
<tr>
<td>OATT</td>
<td>Open Access Transmission Tariff.</td>
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## Charge Allocation Key

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<th>Allocation Category</th>
<th>Market / OATT</th>
<th>Allocation</th>
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<tr>
<td>System 1&lt;sup&gt;st&lt;/sup&gt; Contingency</td>
<td>Market</td>
<td>DA 1&lt;sup&gt;st&lt;/sup&gt; C (excluding at external nodes) is allocated to system DALO. RT 1&lt;sup&gt;st&lt;/sup&gt; C (at all locations) is allocated to System ‘Daily Deviations’. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)</td>
</tr>
<tr>
<td>External DA 1&lt;sup&gt;st&lt;/sup&gt; Contingency</td>
<td>Market</td>
<td>DA 1&lt;sup&gt;st&lt;/sup&gt; C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved</td>
</tr>
<tr>
<td>Zonal 2&lt;sup&gt;nd&lt;/sup&gt; Contingency</td>
<td>Market</td>
<td>DA and RT 2&lt;sup&gt;nd&lt;/sup&gt; C NCPC are allocated to load obligation the Reliability Region (zone) served</td>
</tr>
<tr>
<td>System Low Voltage</td>
<td>OATT</td>
<td>(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations</td>
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<tr>
<td>Zonal High Voltage</td>
<td>OATT</td>
<td>High Voltage Control NCPC is allocated to zonal Regional Network Load</td>
</tr>
<tr>
<td>Distribution - PTO</td>
<td>OATT</td>
<td>Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service</td>
</tr>
</tbody>
</table>
Year-Over-Year Total NCPC Dollars and Energy

* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.
DA and RT NCPC Charges

NOV-13 Total = $5.31 M

Day-Ahead: 59%
Real-Time: 41%

Last 13 Months

Millions

Day-Ahead
Real-Time


$0
$10
$20
$30
$40
$50
NCPC Charges by Type

NOV-13 Total = $5.31 M

Last 13 Months

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage
Daily NCPC Charges by Type
NOV-13 Total = $5.31 M

Last 13 Months

<table>
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<th>Month</th>
<th>System 1stC</th>
<th>Zonal 2ndC</th>
<th>System Low V</th>
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<tr>
<td>Nov13</td>
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Millions

- $0.0
- $10.0
- $20.0
- $30.0
- $40.0
- $50.0

NCPC Charges by Allocation
RT First Contingency Charges by Deviation Type

NOV-13 Total = $1.46 M

- Gen Import: 19.6%
- Inc Load: 10.8%
- Imp Load: 5.9%
- Load: 63.7%

Last 13 Months

Millions

- NOV12: $0
- DEC12: $2
- JAN13: $4
- FEB13: $6
- MAR13: $8
- APR13: $10
- MAY13: $12
- JUN13: $14
- JUL13: $16
- AUG13: $18
- SEP13: $20
- OCT13: $22
- NOV13: $24

Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations
LSCPR Charges by Zone

CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations
NCPC Charges for Voltage Support and High Voltage Control
NCPC Charges by Type

Value of Charges

Millions

- $0
- $25
- $50
- $75
- $100
- $125
- $150

2011 2012 2013


- $74.2
- $87.0
- $135.7
- $22.0
- $45.9
- $7.0
- $7.0
- $5.0
- $9.8
- $21.8
- $4.9
- $4.7
- $2.4
- $5.3

1st C
2nd C
Distr
Voltg
NCPC Charges as Percent of Energy Market

NCPC By Type as Percent of Energy Market

Percent

0.0%
1.0%
2.0%
3.0%
4.0%


1.1%
1.7%
2.0%
2.0%
2.0%
3.5%
1.2%
1.6%
1.2%
2.0%
2.0%
3.5%
1.2%
1.6%
1.2%
2.2%
2.7%
1.1%
1.1%
0.7%
1.4%
First Contingency NCPC Charges

Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market.
Second Contingency NCPC Charges

Value of Charges

% of Energy Market Value

Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market.
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market.
DA vs. RT Pricing

The following slides outline:

- This month vs. prior year’s average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange
## DA vs. RT LMPs ($/MWh)

### Arithmetic Average

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<th>Year 2011</th>
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<th>CT</th>
<th>ME</th>
<th>NH</th>
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<th>RI</th>
<th>SEMA</th>
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### November-12

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<tr>
<td></td>
<td>2.8%</td>
<td>2.7%</td>
<td>3.1%</td>
<td>2.5%</td>
<td>1.2%</td>
<td>2.3%</td>
<td>2.9%</td>
<td>2.2%</td>
<td>2.5%</td>
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</tbody>
</table>

### November-13

<table>
<thead>
<tr>
<th>November-13</th>
<th>NEMA</th>
<th>CT</th>
<th>ME</th>
<th>NH</th>
<th>VT</th>
<th>RI</th>
<th>SEMA</th>
<th>WCMA</th>
<th>Hub</th>
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<tbody>
<tr>
<td><strong>Day-Ahead</strong></td>
<td></td>
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<td></td>
<td>$42.42</td>
<td>$41.77</td>
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<td>$42.33</td>
<td>$42.71</td>
<td>$42.34</td>
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<td><strong>Real-Time</strong></td>
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<td>$45.00</td>
<td>$44.71</td>
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<td>$44.95</td>
<td>$45.27</td>
<td>$44.89</td>
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<td><strong>RT Delta %</strong></td>
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<tr>
<td></td>
<td>6.1%</td>
<td>7.0%</td>
<td>5.7%</td>
<td>5.4%</td>
<td>5.8%</td>
<td>6.2%</td>
<td>6.0%</td>
<td>6.0%</td>
<td>6.3%</td>
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### Annual Diff.

<table>
<thead>
<tr>
<th></th>
<th>NEMA</th>
<th>CT</th>
<th>ME</th>
<th>NH</th>
<th>VT</th>
<th>RI</th>
<th>SEMA</th>
<th>WCMA</th>
<th>Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Yr over Yr DA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>-22.8%</td>
<td>-23.3%</td>
<td>-22.4%</td>
<td>-22.8%</td>
<td>-25.9%</td>
<td>-23.0%</td>
<td>-22.4%</td>
<td>-23.6%</td>
<td>-23.3%</td>
</tr>
<tr>
<td><strong>Yr over Yr RT</strong></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>-20.4%</td>
<td>-20.1%</td>
<td>-20.5%</td>
<td>-20.6%</td>
<td>-22.6%</td>
<td>-20.1%</td>
<td>-20.1%</td>
<td>-20.8%</td>
<td>-20.5%</td>
</tr>
</tbody>
</table>
Monthly Average Fuel Price and RT Hub LMP Indexes
Monthly Average Fuel Price and RT Hub LMP

Real-Time LMP

Gas Price

Oil Price

Underlying natural gas data furnished by:
Reserve Market Results – November 2013

• Maximum potential Forward Reserve Market payments of $9.8M were reduced by credit reductions of $289K, failure-to-reserve penalties of $455K and failure-to-activate penalties of $0, resulting in a net payout of $9.0M or 92% of maximum
  – Rest of System: $5.1M/$6.1M (88%)
  – Southwest Connecticut: $557K/$558K (100%)
  – Connecticut: $3.1M/$3.1M (100%)

• $4.8M total Real-Time credits were reduced by $600K in Forward Reserve Energy Obligation Charges for a net of $4.2M in Real-Time Reserve payments
  – Rest of System: 89 hours, $2.3M
  – Southwest Connecticut: 89 hours, $1.2M
  – Connecticut: 89 hours, $587K
  – NEMA: 89 hours, $184K

* “Failure to reserve” results in both reductions in credits and penalties in the Locational Forward Reserve Market.
LFRM Charges to Load by Load Zone ($)

LFRM Charges by Zone, Last 13 Months

- CT
- ME
- NEMA
- NH
- RI
- SEMA
- VT
- WCMA

Millions

- $0.0
- $2.0
- $4.0
- $6.0
- $8.0
- $10.0

Partial
DA vs. RT Load Obligation: November, This Year vs. Last Year

Monthly, Last 13 Months

Daily, This Year vs. Last Year

DA % of RT

[Graphs showing DA % of RT for monthly and daily comparisons between this year and last year, with data points for November 2012 to November 2013.]
Zonal Increment Offers and Cleared Amounts

November Monthly Totals by Zone

<table>
<thead>
<tr>
<th>Zone</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ME</td>
<td></td>
<td>50,000</td>
</tr>
<tr>
<td>NH</td>
<td></td>
<td></td>
</tr>
<tr>
<td>VT</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CT</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SEMA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WCMA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NEMA</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

MWh

- Cleared
- Offered
Zonal Decrement Bids and Cleared Amounts

November Monthly Totals by Zone

MWh

Hub ME NH VT CT RI SEMA WCMA NEMA

Cleared Bid

Zonal Decrement Bids and Cleared Amounts

November Monthly Totals by Zone

MWh

Hub ME NH VT CT RI SEMA WCMA NEMA

Cleared Bid
Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

Data excludes nodal offers and bids
Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown

- GWh
- November 2012: 28.0%
- December 2012: 23.2%
- January 2013: 26.3%
- February 2013: 22.4%
- March 2013: 25.7%
- April 2013: 23.5%
- May 2013: 26.4%
- June 2013: 25.2%
- July 2013: 29.0%
- August 2013: 30.3%
- September 2013: 27.7%
- October 2013: 27.8%
- November 2013: 22.7%

- Non-Dispatchable
- Dispatchable
DA vs. RT Net Interchange
November 2013 vs. November 2012

Hourly Average by Day, Last Year

Hourly Average by Day, This Year

Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports
Rolling Average Peak Energy Rent (PER)

Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: Home > Markets > Other Markets Data > Forward Capacity Market > Reports and are subject to resettlement.
REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING
Planning Advisory Committee

• RSP13 approved by ISO Board of Directors on November 8

• December 18 PAC Agenda
  – EIPC Gas/Electric Interface Study and Non-grant Work Updates
  – ICF to Present Draft Report on Phase II of the Gas Study
  – Updates on Strategic Analysis Unit Retirement Study and Wind Integration Study
  – Greater Boston Solutions Update
  – NH/VT 2022/2023 Solutions Update
  – SWCT Needs Assessment II
The next meeting will be held at the DoubleTree Hotel in Milford on December 16

• Agenda
  – Discussion of responses to distribution queue data and technical interconnection information request
  – DG Interconnection issues
  – Discussion of ISO’s draft interim PV forecast
  – Summary & next steps
Environmental Advisory Group

- The meeting originally scheduled for December 13 has been postponed until December 20
- Agenda will include regulatory updates and discussions of environmental emissions
## RSP Project Stage Descriptions

<table>
<thead>
<tr>
<th>Stage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Planning and Preparation of Project Configuration</td>
</tr>
<tr>
<td>2</td>
<td>Pre-construction (e.g., material ordering, project scheduling)</td>
</tr>
<tr>
<td>3</td>
<td>Construction in Progress</td>
</tr>
<tr>
<td>4</td>
<td>In Service</td>
</tr>
</tbody>
</table>
## North Shore Upgrades – Salem Harbor Non-Price Retirement

**Status as of 12/2/13**

**Project Benefits:** Allows for the Non-Price Retirement of the Salem Harbor Plant

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Reconductor B-154N King St. - South Danvers 115 kV</td>
<td>Feb-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor C-155N King St. - South Danvers 115 kV</td>
<td>Feb-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor S-145 Tewksbury - North Reading 115 kV</td>
<td>Aug-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor T-146 Tewksbury - North Reading 115 kV</td>
<td>Aug-13</td>
<td>4</td>
</tr>
</tbody>
</table>
Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 12/2/13

*Project Benefit: Improves system reliability for the Lower SEMA area*

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expand the Carver Substation</td>
<td>Jun-13</td>
<td>4</td>
</tr>
<tr>
<td>Build New 345 kV Line from Carver to Vicinity of Bourne Substation and</td>
<td>Jun-13</td>
<td>4*</td>
</tr>
<tr>
<td>connect to Line 120. Expand Bourne with one breaker position.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construct New 115 kV Substation with 345-115 kV Autotransformer and</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Loop Line 115 into the new substation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upgrade the 115 kV Bell Rock to High Hill D21 Line</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Separate the 345 kV (342 / 322) Double Circuit Tower Lines</td>
<td>Jun-13</td>
<td>4</td>
</tr>
</tbody>
</table>

Project approved by MA EFSB on 4/27/12

* The work is in service in a temporary configuration. The final in-service configuration will be completed May 2014.
### NEEWS: Greater Springfield Reliability Project

**Status as of 12/2/13**

**Plan Benefit:** Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New 345 kV Ludlow - Agawam Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Construct New 345 kV Agawam - North Bloomfield Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Expand Existing 115 kV Agawam Station &amp; Construct New 345 kV Yard</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Expand 345 kV North Bloomfield Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Expand &amp; Reconfigure 345 kV Ludlow Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Agawam - Piper Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Agawam - Chicopee Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Construct New 115 kV Cadwell Switching Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor 115 kV Ludlow - Orchard Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Orchard - Cadwell Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Ludlow - Cadwell Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
</tbody>
</table>
### NEEWS: Greater Springfield Reliability Project, cont.

**Status as of 12/2/13**

**Plan Benefit:** Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Build New 115 kV Fairmont Switching Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Piper Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Chicopee Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Cadwell Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Shawinigan Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild 115 kV Ludlow - Shawinigan Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconfigure 115 kV South Agawam Switching Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconfigure 115 kV Southwick - South Agawam Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Two 115 kV South Agawam - Agawam Lines</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Terminate Two 115 kV East Springfield - Cadwell Lines</td>
<td>Dec-13</td>
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</tr>
</tbody>
</table>
## NEEWS: Interstate Reliability Project
### Status as of 12/2/13

**Plan Benefit:** Improves New England reliability by increasing transfer limits of three critical interfaces

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Build New 345 kV Line 3271 Card - Lake Road</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Card 345 kV Substation Expansion</td>
<td>Dec-15</td>
<td>3</td>
</tr>
<tr>
<td>Lake Road 345 kV Substation Expansion</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Build New 345 kV Line 341 Lake Road to CT/RI Border</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Build New 345 kV Line 341 CT/RI Border to West Farnum</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>West Farnum 345 kV Substation Additions</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>New Sherman Road 345 kV Substation</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>West Farnum 115 kV Substation Upgrades</td>
<td>Dec-15</td>
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</tr>
<tr>
<td>Reconduct 345 kV Line 328 West Farnum to Sherman Road</td>
<td>Dec-15</td>
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</tr>
<tr>
<td>Riverside Substation Relay Upgrades</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Woonsocket Substation Relay Upgrades</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Hartford Avenue Substation Relay Upgrades</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Build New 345 kV Line 366 West Farnum to MA/RI Border</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Build New 345 kV Line 366 MA/RI Border to Millbury 3</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Millbury 3 Substation Expansion</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Carpenter Hill Substation Relay Upgrades</td>
<td>Dec-15</td>
<td>1</td>
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</tbody>
</table>
**NEEWS: Central Connecticut Reliability Project**

*Status as of 12/2/13*

*Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces*

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Connecticut Reliability Project (CCRP)*</td>
<td>Jun-17</td>
<td>1</td>
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</tbody>
</table>

*Combined with Greater Hartford Central Connecticut Study*
Maine Power Reliability Program (MPRP)
Status as of 12/2/13

*Project Benefit:* Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

<table>
<thead>
<tr>
<th>New 345 kV Lines</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New Section 3023 Orrington to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Construct New Section 3024 Albion Road to Coopers Mills</td>
<td>Jan-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3025 Coopers Mills to Larrabee Road</td>
<td>Mar-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3026 Larrabee Road to Surowiec</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Construct New Section 3020 Surowiec to Raven Farm</td>
<td>Nov-13</td>
<td>4</td>
</tr>
<tr>
<td>Construct New Section 3021 South Gorham to Maguire Road</td>
<td>Mar-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3022 Maguire Road to Eliot</td>
<td>Jun-14</td>
<td>2</td>
</tr>
</tbody>
</table>

- The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.
Status as of 12/2/13

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

<table>
<thead>
<tr>
<th>New 115 kV Lines</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New Section 254 Orrington to Coopers Mills</td>
<td>Feb-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 243A Livermore Falls to Junction Section 243</td>
<td>Jun-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 251 Livermore Falls to Larrabee Road</td>
<td>May-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 255 Larrabee Road to Middle Street</td>
<td>Apr-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 86A Tap to Belfast</td>
<td>Aug-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 256 Middle Street to Lewiston Lower</td>
<td>April-15</td>
<td>1</td>
</tr>
</tbody>
</table>

- The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.  
Status as of 12/2/13

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

<table>
<thead>
<tr>
<th>115 kV Lines Rebuilds</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rebuild Section 66 Detroit to Wyman Hydro</td>
<td>May-11</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 67 Detroit to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 203 Detroit to Bucksport</td>
<td>Apr-12</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 257 (formerly 67) Coopers Mills to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 258 (formerly 84) Coopers Mills to Albion Road</td>
<td>Aug-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 166 Surowiec to Spring Street</td>
<td>Nov-11</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 167 Surowiec to Moshers</td>
<td>Nov-11</td>
<td>4</td>
</tr>
</tbody>
</table>

- The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.
Status as of 12/2/13

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

<table>
<thead>
<tr>
<th>115 kV Lines Rebuilds (continued)</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rebuild Section 60 Coopers Mills to Bowman Street</td>
<td>Feb-15</td>
<td>3</td>
</tr>
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<td>Rebuild Section 88 Coopers Mills to Augusta East Side</td>
<td>Feb-15</td>
<td>3</td>
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<tr>
<td>Rebuild Section 89 Livermore Falls to Riley</td>
<td>Mar-14</td>
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<tr>
<td>Rebuild Section 229 Riley to Rumford IP</td>
<td>May-13</td>
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<tr>
<td>Rebuild Section 212 Monmouth to Larrabee Road</td>
<td>Feb-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 269 Bowman Street to Monmouth</td>
<td>May-12</td>
<td>4</td>
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<tr>
<td>Rebuild Section 238 Louden to Maguire Road</td>
<td>Feb-12</td>
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<tr>
<td>Rebuild Section 250 Maguire Road to Three Rivers</td>
<td>Dec-13</td>
<td>3</td>
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</tbody>
</table>

• The above listing focuses on major transmission line construction and rebuilding.
**Maine Power Reliability Program, cont.**  
*Status as of 12/2/13*

*Project Benefit:* Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

<table>
<thead>
<tr>
<th>345/115 kV Autotransformers</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
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<tr>
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<td>Apr-13</td>
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<tr>
<td>Install One 345/115 kV Autotransformer at Coopers Mills</td>
<td>Jan-15</td>
<td>2</td>
</tr>
<tr>
<td>Install One 345/115 kV Autotransformer at Larrabee Road</td>
<td>Dec-12</td>
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<tr>
<td>Install One 345/115 kV Autotransformer at Maguire Road</td>
<td>Mar-14</td>
<td>3</td>
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<tr>
<td>Install One 345/115 kV Autotransformer at South Gorham</td>
<td>Nov-09</td>
<td>4</td>
</tr>
</tbody>
</table>

- The above listing focuses on major transmission line construction and rebuilding.
Transmission Siting Update

• NEEWS
  – Rhode Island Reliability Project
    • Received siting approval from Rhode Island authorities
  – Greater Springfield Reliability Project
    • Received siting approval from both Connecticut and Massachusetts authorities
  – Interstate Reliability Project
    • National Grid siting application was filed in MA on 6/21/12
    • National Grid siting application was filed in RI on 7/19/12
    • CL&P’s siting hearings in CT were completed on 8/30/12
    • Received siting approval from CT on 1/2/13. The RI Energy Facilities Siting Board approved the project on 6/14/13. Siting proceeding in MA is ongoing.

• MPRP
  – Project filed with the Maine Public Utility Commission on 7/1/08
  – Maine PUC approved most of the project on 6/10/10
  – Hearings are complete - written order received on Lewiston Loop
  – Transmission Cost Allocations are being revised to reflect the new version of the project
Status of Tariff Studies

The chart displays the status of tariff studies over various months from November 2012 to November 2013. It categorizes projects into different stages:

- Distribution
- Executed IA
- Negotiating IA
- Facility Study
- Scoping
- Optional Study
- Sys. Impact Study
- Feasibility Study

The number of projects in each category is represented by the height of the bars, with colors indicating the specific stage of the project.

Numbers of MW are also indicated at the bottom of the chart, which could be related to the size or capacity of the projects.
OPERABLE CAPACITY ANALYSIS

Fall 2013 and Winter 2013/2014
## Winter 2013-2014 Operable Capacity Analysis

### 50/50 Load Forecast (Reference)

<table>
<thead>
<tr>
<th>Description</th>
<th>January-2014 2</th>
<th>January-2014 2</th>
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</thead>
<tbody>
<tr>
<td>Generator Operable Capacity MW 1</td>
<td>29,714</td>
<td>34,242</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
<td>398</td>
<td>398</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
<td>168</td>
<td>168</td>
</tr>
<tr>
<td>Operable Capacity Generator with OP-4 DR and RTEG</td>
<td>30,280</td>
<td>34,808</td>
</tr>
<tr>
<td>External Node Available Net Capacity, CSO imports minus firm capacity exports (+)</td>
<td>1,083</td>
<td>1,083</td>
</tr>
<tr>
<td>Non Commercial Capacity (+)</td>
<td>122</td>
<td>122</td>
</tr>
<tr>
<td>Non Gas-fired Planned Outage MW (-)</td>
<td>1,059</td>
<td>1,115</td>
</tr>
<tr>
<td>Allowance for Unplanned Outages (-)</td>
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<td>2,800</td>
</tr>
<tr>
<td>Gas Generator Outages MW (-)</td>
<td>1,402</td>
<td>1,476</td>
</tr>
<tr>
<td>Generation at Risk Due to Gas Supply (-) 4</td>
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<td>2,522</td>
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<td>Net Capacity (NET OPCAP SUPPLY MW) 3</td>
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<td>Peak Load Forecast MW (adjusted for Other Demand Resources) 2</td>
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<td>Operating Reserve Requirement MW</td>
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<td>Operable Capacity Required (NET LOAD OBLIGATION MW)</td>
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<td>Operable Capacity Margin 3</td>
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</table>

1 Generator Operable Capacity is based on data as of November 18th, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

2 Based on week with lowest Operable Capacity Margin, week beginning January 18th, 2014

3 Includes OP4 actions associated with RTEG and RTDR

4 Total of (Gas at Risk MW) – (Gas Gen Outages MW)
## Winter 2013-2014 Operable Capacity Analysis

<table>
<thead>
<tr>
<th>90/10 Load Forecast (Extreme)</th>
<th>January-2014&lt;sup&gt;2&lt;/sup&gt;</th>
<th>January-2014&lt;sup&gt;2&lt;/sup&gt;</th>
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<tr>
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<td>SCC</td>
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<tr>
<td>Generator Operable Capacity MW&lt;sup&gt;1&lt;/sup&gt;</td>
<td>29,714</td>
<td>34,242</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
<td>398</td>
<td>398</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
<td>168</td>
<td>168</td>
</tr>
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<tr>
<td>Gas Generator Outages MW (-)</td>
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<td>1,476</td>
</tr>
<tr>
<td>Generation at Risk Due to Gas Supply (-)</td>
<td>3,229</td>
<td>3,588</td>
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<td>Net Capacity (NET OPCAP SUPPLY MW)&lt;sup&gt;3&lt;/sup&gt;</td>
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<tr>
<td>Operating Reserve Requirement MW</td>
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<tr>
<td>Operable Capacity Required (NET LOAD OBLIGATION MW)</td>
<td>24,309</td>
<td>24,309</td>
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<tr>
<td>Operable Capacity Margin&lt;sup&gt;3&lt;/sup&gt;</td>
<td>(1,314)</td>
<td>2,725</td>
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</table>

1. Generator Operable Capacity is based on data as of November 18<sup>th</sup>, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

2. Based on week with lowest Operable Capacity Margin, week beginning January 18<sup>th</sup>, 2014.

3. Includes OP4 actions associated with RTEG and RTDR

4. Total of (Gas at Risk MW) – (Gas Gen Outages MW)
Winter 2013-2014 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

New England Operable Capacity Margins - CSO with RTDR & RTEG
50/50 FORECAST

Operable Capacity Margin (MW)

December 7, 2013 - March 29, 2014, W/B Saturday
Winter 2013-2014 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

New England Operable Capacity Margins - CSO with RTDR & RTEG
90/10 FORECAST

Operable Capacity Margin (MW)

December 7, 2013 - March 29, 2014, W/B Saturday
Winter 2013-2014 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS
December 6, 2013 - 50/50 - FORECAST - CSO

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

<table>
<thead>
<tr>
<th>STUDY WEEK (Week Beginning, Saturday)</th>
<th>AVAILABLE OPCAP MW</th>
<th>EXTERNAL NODE AVAIL CAPACITY MW</th>
<th>NON-GAS CSO MW</th>
<th>ALLOWANCE FOR UNPLANNED OUTAGES MW</th>
<th>GAS GENERATOR OUTAGES MW</th>
<th>GAS AT RISK MW</th>
<th>NET OPCAP SUPPLY MW</th>
<th>PEAK LOAD FORECAST MW</th>
<th>OPER RESERVE REQUIREMENT MW</th>
<th>NET LOAD OBLIGATION MW</th>
<th>OPCAP MARGIN MW</th>
<th>OPCAP FROM OP4 ACTIONS through OP4 Step 2 MW</th>
<th>OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW</th>
<th>OPPAC MARGIN w/ OP4 actions through OP4 Step 6 MW</th>
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<td>398</td>
<td>1,367</td>
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</tr>
</tbody>
</table>

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(8 + 10 = 11)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
### ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

**December 6, 2013 - 90/10- FORECAST - CSO**

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

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<tr>
<th>STUDY WEEK (Week Beginning, Saturday)</th>
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<th>NON-GAS PLANNED OUTAGES MW</th>
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<th>GAS GENERATOR OUTAGES MW</th>
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<th>OPCAP MARGIN MW</th>
<th>OPCAP FROM OP4 ACTIONS 2 REAL-TIME EMER. GEN MW</th>
<th>OPCAP FROM OP4 ACTIONS 3 MW</th>
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<tbody>
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<td>12/7/2013</td>
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<td>114</td>
<td>1,474</td>
<td>3,200</td>
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<td>2,700</td>
<td>776</td>
<td>150</td>
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<td>18,565</td>
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<td>20,940</td>
<td>1,305</td>
<td>461</td>
<td>1,766</td>
<td>234</td>
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</table>

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator DARD Outages for the period. This value would also include any known long-term Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2013 CELT Report adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula (8 + 10 = 11)
12. OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. This does not include Emergency Energy Transactions (EETs).
OPERABLE CAPACITY ANALYSIS

Appendix
## Possible Relief Under OP4 based on OP4 Appendix A

<table>
<thead>
<tr>
<th>OP 4 Action Number</th>
<th>Page 1 of 2 Action Description</th>
<th>Amount Assumed Obtainable Under OP 4</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.</td>
<td>0¹ 600</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Dispatch real time Demand Resources.</td>
<td>Dec 268 Jan-March 398 ³</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Voluntary Load Curtailment of Market Participants’ facilities.</td>
<td>40²</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Implement Power Watch</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Voltage Reduction requiring &gt; 10 minutes Dispatch real time Emergency Generation</td>
<td>134 ⁴ Dec 127 Jan-March 168 ³</td>
<td></td>
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<tr>
<td>7</td>
<td>Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes</td>
<td>0</td>
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</tr>
<tr>
<td>8</td>
<td>Voltage Reduction requiring 10 minutes or less</td>
<td>267 ⁴</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.</td>
<td>5</td>
<td>200²</td>
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</table>
Possible Relief Under OP4 based on OP4 Appendix A

<table>
<thead>
<tr>
<th>OP 4 Action Number</th>
<th>Page 2 of 2 Action Description</th>
<th>Amount Assumed Obtainable Under OP 4 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning</td>
<td>200&lt;sup&gt;2&lt;/sup&gt;</td>
</tr>
<tr>
<td>11</td>
<td>Request State Governors to Reinforce Power Warning Appeals.</td>
<td>100&lt;sup&gt;2&lt;/sup&gt;</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>Dec = 2,941</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Jan-Mar = 3,112</td>
</tr>
</tbody>
</table>

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of November 18<sup>th</sup>, 2013.
4. The MW values are based on a 26,690 MW system load and the most recent voltage reduction test % achieved.
III.13.7.2.7 Exception.

(a) Intermittent Power Resources shall be exempt from provisions set forth in this Section III.13.7.2.
Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3. During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

### III.13.7.2 Capacity Performance Payments

#### III.13.7.2.1 Definition of Capacity Scarcity Condition

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

#### III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition.
(a) A Generating Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the resource’s output during the interval plus the resource’s Real-Time Reserve Designation (including any regulation capability available but not used for energy) applicable to the particular Capacity Scarcity Condition for the hour in which the Capacity Shortage Condition occurred; provided, however, that if the resource’s output was limited during the Capacity Scarcity Condition as a result of a binding transmission constraint, then the resource’s Actual Capacity Provided may not be greater than the resource’s Desired Dispatch Point 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 Shortage Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Shortage Condition occurred where a single Market Participant owns more than one Import Capacity Resource associated with a single interface, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource On-Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource On-Peak Hours and shall be zero.

(d) A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource Seasonal Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource Seasonal Peak Hours and shall be zero.

(e) A Real-Time Emergency Generation Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as
registered with the ISO during the interval in which the Capacity Shortage Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Shortage Condition occurred; and shall be multiplied by 1.08.

(f) A Demand Response Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource’s Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exits, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

\[
\frac{(\text{Load} + \text{Reserve Requirement})}{\text{Total Capacity Supply Obligation}}
\]

(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute
Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning 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.

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves 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 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).

Reserve Requirement = the local Thirty-Minute Operating 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.
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 local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

(ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.
Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative.

III.13.7.2.5 Capacity Performance Payment Rate.
For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed annually and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.
III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Payment for an interval shall equal the resource’s Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Rate for an interval may be positive or negative.

III.13.7.2.7 Exceptions:

(a) Existing Import Capacity Resources associated with the NYPA contracts listed in Section III.13.1.3.3(c) shall be exempt from provisions set forth in this Section III.13.7.2, provided that the associated transactions are self-scheduled and perform according to their contract terms.

(b) A resource’s Capacity Performance Score shall be set to zero if that resource’s inability to deliver energy or reserves during a Capacity Scarcity Condition is due to either:

   i. a Planned Outage that was scheduled and approved in accordance with ISO New England Operating Procedure No. 5 – Generation and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5); or

   ii. a loss of a transmission facility that is beyond the control of the resource.
RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2014

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 Committee; and

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2014 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 2014 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair    Joel S. Gordon
Vice-Chair   Timothy J. Brennan
Vice-Chair   Brian E. Forshaw
Vice-Chair   August G. “Gus” Fromuth
Vice-Chair   Doug Hurley
Vice-Chair   Thomas W. Kaslow
Secretary   David T. Doot
Assistant Secretary  Paul N. Belval
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Joel Gordon, Chairman, NEPOOL Budget and Finance Subcommittee
       Paul N. Belval, NEPOOL Counsel

DATE: November 27, 2013

RE: Estimated Budget for 2014 Participant Expenses

The Participants Committee will be asked at its December 6 meeting to approve the estimated NEPOOL expense budget for 2014, which is attached to this memorandum (the “2014 Budget”). As we did in prior years, we have prepared the 2014 Budget to compare the estimated expenses for 2014 to both the estimated 2013 expenses approved by the Participants Committee in December 2012 and the current forecast for actual expenses for 2013. (Attachment A) The 2014 Budget reflects a slight reduction in NEPOOL expenses from the 2013 budget. We have also attached a calculation of the per-Participant share of the 2014 Budget expenses, comparing that amount to the same figures from five years ago, which generally shows a reduction in per-Participant NEPOOL expenses over that five-year period. (Attachment B)

Consistent with the practice in previous years, the NEPOOL Budget and Finance Subcommittee (the “Subcommittee”) has worked with NEPOOL Counsel, the ISO and NEPOOL’s Independent Financial Advisor to develop the 2014 Budget. At its November 18 teleconference, the Subcommittee discussed the proposed 2014 Budget and recommended its adoption without objection. During the Subcommittee’s discussion, one member inquired about the need to continue with credit insurance for those Market Participants not providing collateral under the ISO-NE Financial Assurance Policy. ISO-NE said it would look into that issue in 2014.

The following form of resolution may be used in acting on the 2014 Budget:

RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2014 as presented at this meeting.
## ESTIMATED 2014 NEPOOL BUDGET COMPARED TO 2013 NEPOOL BUDGET AND 2013 PROJECTED ACTUAL EXPENSES

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<th>2014 Proposed Budget</th>
<th>2013 Approved Budget</th>
<th>2013 Current Forecast</th>
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</tr>
<tr>
<td>CFTC Counsel (5)</td>
<td>$ 0</td>
<td>$ 10,000</td>
<td>$ 40,000 (6)</td>
</tr>
<tr>
<td>Generation Information System (3)</td>
<td>$1,065,000</td>
<td>$1,065,000</td>
<td>$1,046,000</td>
</tr>
<tr>
<td>Credit Insurance Premium (3)</td>
<td>$ 450,000</td>
<td>$ 425,000</td>
<td>$ 425,000</td>
</tr>
<tr>
<td>NEPOOL Audit Management Subcommittee (“NAMS”) Consultant (7)</td>
<td>$ -</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>SUBTOTAL EXPENSES</td>
<td>$6,008,000</td>
<td>$6,007,000</td>
<td>$6,005,000</td>
</tr>
</tbody>
</table>

### Revenue

- NEPOOL Membership Fees (3) (8)                      | ($1,800,000)         | ($1,750,000)         | ($1,855,000)          |
- Generation Information System (3) (9)               | ($1,065,000)         | ($1,065,000)         | ($1,046,000)          |
- Credit Insurance Premium (3) (10)                   | ($ 450,000)          | ($ 425,000)          | ($ 425,000)           |
| TOTAL REVENUE                                        | ($3,315,000)         | ($3,240,000)         | ($3,326,000)          |

**TOTAL NEPOOL EXPENSES**                              | **$2,693,000**       | **$2,767,000**       | **$2,679,000**        |
Notes

(1) 2014 NEPOOL Counsel fees and disbursements are estimated to remain consistent with 2013 budgeted and actual levels.

(2) 2014 proposed estimate provided by Michael M. Mackles, NEPOOL’s Independent Financial Advisor.

(3) 2014 proposed estimate provided by ISO New England Inc. (“ISO”).

(4) 2014 proposed estimate (a $4,000 reduction from 2013) reflects the following: (i) no change to current Review Board arrangements; (ii) three or fewer appeals in 2014; (iii) no change in the annual retainer paid to two of the three members of the Review Board, which is $36,000; and (iv) agreement to remove the prior $4,000 additional compensation paid to the Board’s Chairman, such that the Chairman, also, will receive payments based on annual retainer of $36,000.

(5) Reflects a $10,000 reduction from 2013 estimates given the fact that the final CFTC exemption order was issued in March 2013, and as a result no additional budget for CFTC Counsel is proposed for 2014.

(6) Includes amounts paid to CFTC Counsel in 2013 for work performed and budgeted in 2012.

(7) An operational audit of the ISO could be performed in 2014, and if NEPOOL were to decide to retain a professional to assist in such an audit, some amount would be required for this item. Historically, the NEPOOL Participants Committee has voted separately on funds for any such professional.

(8) The 2014 proposed estimate is based on the 2013 actual receipts through October 2013, plus a forecast (a) for new members, of 5 members at $5,000 each, 4 members at $1,000 each, 3 members at $500 each, and (b) for terminated members, of 16 at $5,000 each, 3 at $1,250 each, and 6 at $500 each.

(9) Generation Information System costs are paid by “GIS Participants” under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002.

(10) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy.
# ESTIMATED BREAKDOWN OF PROJECTED 2014 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2014 figures assume no change in current NEPOOL membership)
(2009 figures as projected and budgeted at 2008 Annual Meeting)

## CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)</td>
<td>$4,493,000</td>
<td>$4,608,000</td>
</tr>
<tr>
<td>B. Projected NEPOOL Membership Fees</td>
<td>$1,800,000</td>
<td>$1,400,000</td>
</tr>
<tr>
<td>C. Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)</td>
<td>$2,693,000</td>
<td>$3,208,000</td>
</tr>
<tr>
<td>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 2014 is based on 2012 peak loads of MPEU members)</td>
<td>$100,000</td>
<td>$65,930</td>
</tr>
<tr>
<td>E. Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2014 is estimated amount based on 2013 membership data)</td>
<td>$120,000</td>
<td>$116,017</td>
</tr>
<tr>
<td>F. Total Amount paid by DRP-Only and ODR-Only Customers</td>
<td>n/a</td>
<td>$41,450</td>
</tr>
<tr>
<td>G. Large Renewable Generation Sub-Sector Share (C x 2% x lrgs)</td>
<td>$161,580</td>
<td>$128,320</td>
</tr>
<tr>
<td>H. Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D + E + F+ G))</td>
<td>$2,311,420</td>
<td>$2,856,183</td>
</tr>
</tbody>
</table>

## CALCULATION OF SECTOR ALLOCATIONS

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Amount to be allocated to each of the Remaining Sectors (H ÷ 4)</td>
<td>$577,855</td>
<td>$714,046</td>
</tr>
<tr>
<td>J. Total Amount paid by Related Person Suppliers (2 voting members) (I ÷ s) x rps</td>
<td>$9,963</td>
<td>$7,847</td>
</tr>
<tr>
<td>K. Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)</td>
<td>$1,307,327</td>
<td>$1,548,564</td>
</tr>
</tbody>
</table>
### L. Total Amount of Provisional Generation Share shared equally by Generation Sector Provisional Members

\[
(0.02 \div \text{gprov}_y \times K) \times (g_y \div (g_y + (s_y - \text{rps}_y) + \text{lr}_{g}))
\]

<table>
<thead>
<tr>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0</td>
<td>$4,631</td>
</tr>
</tbody>
</table>

### M. Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector (excluding provisional group voting member), Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers

\[
((K - L) \div (g_y + (s_y - \text{rps}_y) + \text{lr}_{g}))
\]

<table>
<thead>
<tr>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>$10,134</td>
<td>$14,429</td>
</tr>
</tbody>
</table>

### N. Transmission Sector Share per full voting member

\[
((N-O) \div t_y)
\]

<table>
<thead>
<tr>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>$82,138</td>
<td>$100,987</td>
</tr>
</tbody>
</table>

### O. Provisional Transmission Sector member share

\[
(I \times (tprov_y \times 0.005))
\]

<table>
<thead>
<tr>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>$2,889</td>
<td>$7,140</td>
</tr>
</tbody>
</table>

### P. Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)\(^1\)

\[
(I \div \text{poe}_y)
\]

<table>
<thead>
<tr>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>$10,506</td>
<td>$13,472(^2)</td>
</tr>
</tbody>
</table>

### ANNUAL VARIABLES

<table>
<thead>
<tr>
<th>Variable</th>
<th>2014</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>(s_y)</td>
<td>116</td>
<td>91</td>
</tr>
<tr>
<td>(\text{rps}_y)</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>(g_y)</td>
<td>12</td>
<td>15</td>
</tr>
<tr>
<td>(\text{gprov}_y)</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>(\text{lr}_{g})</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>(t_y)</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>(\text{tprov}_y)</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>(\text{poe}_y)</td>
<td>55</td>
<td>48</td>
</tr>
</tbody>
</table>

\(^1\) The Publicly Owned Entity Sector share of Participant Expenses amongst them. The member share noted is indicative of the share a Publicly Owned Entity which does not participate in this arrangement would pay.

\(^2\)
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian M. Lombardi, NEPOOL Counsel

DATE: November 27, 2013

RE: IMM-Proposed Offer Review Trigger Prices for FCA 9

At its December 6, 2013 meeting, the Participants Committee will be asked to consider supporting IMM-proposed revisions to Market Rule 1, Appendix A regarding Offer Review Trigger Prices (ORTP) for the ninth Forward Capacity Auction (FCA 9), the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation (the “ORTP Updates”). This memorandum provides further detail on the ORTP Updates and also discusses potential Participant-sponsored amendments to this proposal of which we have been advised.

By way of brief background, in response to multiple FERC FCM Redesign orders,1 the ISO has implemented a buyer-side mitigation mechanism that imposes offer floors on new resources offering into the FCA. Beginning with the eighth Forward Capacity Auction (FCA 8), the ISO has established a series of benchmark offer prices, which are referred to as Offer Review Trigger Prices, for various resource types. New resources can offer in the FCA at prices equal to or greater than its ORTP with no IMM cost review. If new resources wish to offer their capacity at prices below the ORTP, they must submit resource-specific cost data to IMM for evaluation. Under those provisions, the IMM may either establish ORTPs for resource types that are expected to be built in the near future or conduct asset-specific reviews on projects that seek to submit offers lower than the relevant ORTP. New resources retain the right to file under Section 206 of the Federal Power Act to seek an exemption from the ORTP.

While ORTPs have been approved by the FERC for FCA 8, the Market Rules require that the ORTPs must be recalculated every third year with updates completed in the following two years based on commonly used indices to capture year-on-year changes in the net cost of new entry calculations. As such, the IMM has updated ORTPs to be used for participation in FCA 9. In addition, the IMM has proposed a revised methodology for Demand Response ORTP and developed a proposed annual indexation approach for years between full recalculation. A copy of the IMM’s proposed Appendix A revisions are included with this memorandum as Attachment A.

At its November 13-14, 2013 meeting, the Markets Committee considered, but failed to recommend Participants Committee support for the IMM-proposed ORTP Updates with a 16.57% Vote in favor.2 Prior to the Markets Committee’s vote on the IMM’s ORTP Updates,

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2 The individual Sector votes on the IMM’s unamended proposal were Generation (0.95% in favor, 16.22% opposed), Transmission (8.58% in favor, 8.59% opposed, 2 abstentions), Supplier (2.15% in favor, 15.02% opposed, 10
four motions to amend the main motion were considered. While two amendments failed to garner the requisite 60% Vote threshold required for Markets Committee support, two other amendments were supported by the Markets Committee. Accordingly, a twice-amended main motion (as amended by EnerNOC and EMJ) was also considered by the Markets Committee. That amended motion received a 56.24% Vote in favor, and accordingly was not recommended for Participants Committee support. A copy of the November 13-14, 2013 Notice of Actions of the Markets Committee detailing these votes, including amendments proposed at the Markets Committee, is also included with this memorandum as Attachment B.

### Potential Motions to Amend the IMM’s ORTP Updates

Consistent with the actions taken by the Markets Committee, the following four motions to amend the main motion have been identified to us as proposals that may be presented for consideration by the Participants Committee at its December 6 meeting: (Further details on these amendments are included with this memorandum)

**A. EnerNOC Amendment**

This amendment, offered by EnerNOC, would add a new Section III.13.1.4.2.4 to Market Rule 1 as follows:

> III.13.1.4.2.4 Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers.

> A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type.

The EnerNOC amendment passed with a 68.86% Vote in favor (Agenda Item 2, “Vote 1” in the Notice of Actions). See Attachment C.

**B. NextEra Amendment**

The NextEra amendment would revise the IMM proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Shore Wind</td>
<td>$0.008.53</td>
</tr>
</tbody>
</table>

abstentions), Alternative Resources (4.28% in favor, 9.89% opposed, 3 abstentions), Publicly Owned Entity (0.61% in favor, 16.56% opposed, 11 abstentions), and End User (0% in favor, 17.17% opposed, 1 abstention).

3 The individual Sector votes on the twice-amended main motion were Generation (1.91% in favor, 15.26% opposed, 1 abstention), Transmission (17.17% in favor, 0% opposed), Supplier (1.91% in favor, 15.26% opposed, 9 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 2 abstentions), Publicly Owned Entity (3.92% in favor, 13.25% opposed, 4 abstentions), and End User (17.17% in favor, 0% opposed).
See Attachment D. The NextEra amendment did not achieve Markets Committee support with a 32.43% Vote in favor (Agenda Item 2, “Vote 2” in the Notice of Actions).

C. **EMI Amendment**

The Energy Management, Inc. (EMI) amendment would revise the IMM proposed Section III.A.21.1.1 of Market Rule 1 by adding Off-Shore Wind to the table as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off-Shore Wind</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

This EMI amendment was supported by the Markets Committee with a 68.12% Vote in favor (Agenda Item 2, “Vote 3” in the Notice of Actions). See Attachment E.

D. **Exelon Amendment**

The Exelon Amendment would revise the IMM proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>$13.22415.04</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.86610.18</td>
</tr>
</tbody>
</table>

See Attachment F. Based on a show of hands vote, this amendment failed to obtain Markets Committee support (Agenda Item 2, “Vote 4” in the Notice of Actions).

If any Participant wishes to offer amendment(s) not already included with this memorandum, we strongly urge that they be provided to NEPOOL Counsel as soon as possible so that they can be reviewed and considered ahead of the meeting and be seen by those who participate in the meeting telephonically. You can e-mail any such proposals to NEPOOL Counsel (slombardi@daypitney.com).

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

RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A regarding Offer Review Trigger Prices (ORTP) for the ninth Forward Capacity Auction (FCA 9), the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation, as proposed by the ISO’s Internal Market Monitor and 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 and Vice-Chair of the Markets Committee.
To: NEPOOL Markets Committee  
From: David Naughton and Robert Laurita - Internal Market Monitor  
Date: November 6, 2013  
Subject: Offer Review Trigger Prices

This memo addresses several issues raised by committee members during the October 9-10 NEPOOL Markets Committee meeting regarding the Internal Market Monitor’s (“IMM”) proposed Offer Review Trigger Prices (“ORTP”). Specifically, the memo addresses:

- the IMM’s proposal to use asset-specific reviews for off-shore wind projects and demand resources using distributed generation, rather than establishing ORTPs for those resource types;
- the IMM’s proposed ORTP for on-shore wind projects; and
- the IMM’s proposed cost of capital used in the calculation of the ORTPs.

I. Background

In its April 13, 2011 order, the Federal Energy Regulatory Commission (“Commission” or “FERC”) directed ISO New England Inc. (the “ISO”) to work with stakeholders to develop and implement a buyer-side mitigation mechanism that would impose offer floors on new resources offering into the Forward Capacity Auction (“FCA”).¹ On December 3, 2012, in compliance with the April 13 Order,

the ISO filed new provisions in Appendix A to Market Rule 1. The FERC accepted those provisions on February 12, 2013. Under those provisions, the IMM may either establish ORTPs for resource types that are expected to be built in the near future or conduct asset-specific reviews on projects that seek to submit offers lower than the relevant ORTP. Moreover, the FERC orders clearly state that Market Participants may file under Section 206 of the Federal Power Act to seek an exemption from the ORTP.

As explained in the ISO’s December 3 Filing, the resource types for which ORTPs were developed reflect the vast majority of resources built in recent years and expected to be built in the near future. There is no need to develop and maintain benchmark prices for resource types that will be built only rarely since these can be reviewed on a case-by-case basis using resource-specific information.

In accepting the buyer-side mitigation mechanism submitted in the December 3 Filing, the Commission held that “[t]rigger prices form a screen: offers at or above the trigger price are accepted into the FCA with no further review; offers below the trigger price may nevertheless be accepted into the FCA if they are justified with the IMM during the unit-specific review process.” FERC found that the ISO’s proposal was in compliance with the Commission’s requirement because it allows a resource to cost-justify a new resource offer floor price that is lower than the relevant trigger price.

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4 April 13 Order at PP 167, 169.

5 Id. at P 20; February 12 Order at P 98.

6 December 3 Filing at 11.

7 February 12 Order at P 38.

8 Id. at P 53.
The ORTP is a threshold price that applies to an entire class of resources. Offers above the ORTP are not reviewed and, therefore, the IMM must be reasonably confident that Market Participants offering above the ORTP are unlikely to exercise buyer-side market power and suppress capacity market prices. Conversely, offers below the ORTP are reviewed by the IMM to determine whether to mitigate the offer upwards. Because offers above the ORTP are not reviewed, the IMM believes that the decision to establish an ORTP should not be made hastily. Rather, the ORTP should be based on detailed data and information from a third-party independent source. Further, the ORTP should be based on a thorough analysis of similar actual projects representing an entire class of resources that have been, or are likely to be, constructed in the New England region during the Capacity Commitment Periods associated with FCA 9 through FCA 12.

If the IMM concludes that it has sufficient detailed data and information on actual or forecasted project costs, revenues and performance such that the resulting ORTP is a reasonable estimate of the lower end of the capacity market revenue requirements at the competitive range for that entire class of resources, then it is appropriate for the IMM to establish an ORTP for that resource type. If the IMM does not have sufficient detailed data or information, then resource-specific reviews are more appropriate.

The IMM is particularly concerned that the ORTP not become an instrument to circumvent the intent of the Minimum Offer Price Rule. If the IMM prematurely sets an ORTP for a resource class too low, that decision increases the risk of projects with out-of-market revenue qualifying to participate in the FCA and being able to remain in the auction at a lower price than they would had the projects been subject to an asset-specific review. Such an outcome could result in a buyer exercising market power, inappropriately suppressing FCM prices.

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9 See February 12 Order at P 38 ("we are satisfied by ISO-NE’s rationalization that, in the case of New England, use of trigger prices at the low end of the spectrum strikes a reasonable balance by not subjecting clearly competitive offers to IMM evaluation, but only addressing those offers that plainly appear commercially implausible absent out-of-market revenues").
II. IMM Response to Issues Raised by Stakeholders

A. ORTP for Off-Shore Wind

Over the past few months, the IMM has consistently explained the methodology it uses to calculate ORTPs. Assumptions regarding the underlying technology and siting location are made and form the basis for calculating the cost of new entry for a proxy plant for each class of resource. The IMM uses a “bottom-up” approach that disaggregates project capital costs, operations and maintenance costs, and expected revenues into categories such as equipment, labor, interconnection costs, land, fuel inventories, etc. This approach provides transparency into the assumptions underlying the ORTP calculations. The IMM has applied this “bottom up” approach for combustion turbines, combined cycle, solar and on-shore wind projects. The IMM was able to do so because detailed cost data was available for each of those types of projects through independent third-party sources, and/or the IMM has sufficient experience reviewing similar projects so as to be confident in the results.

The data recently provided by stakeholders for off-shore wind projects included total project costs but did not include sufficient details to conduct a “bottom-up” analysis. Although many reports containing various levels of information were cited, those reports include many caveats that caution the use of the data for commercial purposes. The IMM and its consultants have neither access to detailed cost data nor sufficient confidence in the data provided by stakeholders to perform a bottom-up analysis of the cost-of-new entry of a proxy off-shore wind farm in New England. Therefore, the IMM was unable to calculate an ORTP for off-shore wind. As a result, under the IMM’s proposal, off-shore wind projects will be subject to resource-specific cost review. To date, the IMM has reviewed cost data for only one New England-based off-shore wind project. In contrast, the IMM has reviewed detailed cost data for numerous on-shore wind projects, combined cycle generators, combustion turbines, and solar projects. While there may be the potential for future off-shore wind projects, presently there is not enough data or experience on off-shore wind resources in the New England region for the IMM to gain the level of confidence needed to establish an ORTP for off-shore wind.

Some committee members have claimed that the lack of an ORTP for off-shore wind resources will create an “un-level playing field,” and will result in investor uncertainty. They claim that an ORTP for
off-shore wind resources is critically important to project financing. The IMM disagrees. First, project financing is not dependent on the existence of an ORTP, as explained in the Commission’s response to a similar argument made by the Eastern Massachusetts Consumer-Owned Systems (“EMCOS”) in response to the December 3 Filing of the current ORTPs. Specifically, the EMCOS argued that the unit-specific review process created uncertainty about the timing and availability of future revenue streams that would complicate efforts to finance projects, that such a burden was being imposed uniquely on public power projects, and that, as a result, the ISO’s proposal was unduly discriminatory. The Commission, however, rejected the EMCOS’ argument in the February 12 Order. In doing so, FERC stated:

We do not agree with EMCOS that the unit-specific review process creates undue uncertainty or imposes an unduly discriminatory burden on public power projects. Unit specific review will conclude prior to the FCA, which will occur three years in advance of the applicable capacity commitment period, and thus, in advance of the time when most developers must make significant construction expenditures to build their new projects. Developers, including developers of public power projects, will have the results of their unit specific review prior to the applicable FCA, and thus, prior to the time when financing must be in place for most construction expenditures.

Second, the capital budget model that the IMM uses to conduct asset-specific reviews is readily available for any developer to evaluate its own project. It is reasonable to assume that an investor interested in an off-shore wind project will expect the project developer to make available the same level of detailed assumptions about the proposed project (i.e., material costs, labor costs, interconnection costs, revenue projections, etc.), which are the very same inputs to the IMM’s capital budget model. The off-shore wind developer can use the IMM’s capital budget model to determine the minimum offer price that the IMM would accept for its project and make the results available to potential investors.

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10 February 12 Order at P 48.

11 Id. at P 56.
B. ORTP for Demand Resources using Distributed Generation

A committee member proposed that the IMM calculate an ORTP for demand resources that use distributed generation for load management purposes. The data provided by the committee member was high level and did not include any bottom-up details. For similar reasons as stated above, the IMM believes there is insufficient detailed information on demand resources using distributed generation for load management in the New England region for the IMM to calculate an ORTP at this time.

The IMM understands the problem facing market participants seeking to propose demand resources using distributed generation to reduce load. It is difficult to know the specific retail customers and the technologies those customers will use to reduce load three years in advance of marketing to the customers.

The IMM believes there may be situations when it is reasonable to allow a retail customer using distributed generation to reduce load to register under a "load management" demand resource. Essentially, a customer serving their own load by starting a distributed generator can have the same effect on the grid as the customer turning off a large motor.

On the other hand, the IMM believes there may be situations where it is not reasonable to allow a retail customer to register its distributed generator as load management. For example, the IMM is concerned about certain distributed generation technologies that may not qualify as a generation resource in the FCM being built "behind the meter" of a retail customer and then, after construction, participating in the FCM as a demand resource.12

Given these considerations, setting the ORTP for demand resources with distributed generation to the low level advocated by the committee member is not appropriate. The IMM is willing, instead, to consider ways to enable the same type of asset-specific cost review that would occur at the FCM qualification stage to occur at the asset registration stage. This approach would allow some, but not all

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12 For example, a distributed generator receiving out-of-market revenues may not qualify to participate in the FCM as a generator; however that same project could be constructed behind the meter of a retail customer load and later register as a demand resource.
necessarily all, distributed generators to be registered as load management. However, such a rule and its implementation should be carefully designed.

C. ORTP for On-Shore Wind

Some stakeholders have claimed that the capacity factor value of 35% assumed in developing the ORTP for on-shore wind is not sufficiently justified. The IMM has reviewed this assumption against the project-specific details provided as part of the ORTP review process conducted for prior FCAs and found that the assumption is consistent with the project-specific data available. In addition, stakeholders should take note of the information provided at the October 9-10 Markets Committee meeting, specifically Slide 7 of the IMM’s presentation, which shows that any capacity factor assumption greater than 31.3% results in an ORTP of $0/kw-month. Consistent with the purpose of the analysis, the IMM believes that the recommended ORTP, and the underlying assumptions, reasonably support a value at the low end of the spectrum as approved in FERC’s February 12 Order.

D. Cost of Capital

Exelon has proposed to adopt the weighted-average cost of capital (“WACC”) assumption used by the NYISO for the purposes of establishing its Installed Demand Capacity Curve. The NYISO WACC is 8.3% compared to the Brattle and IMM proposed assumption of 7.2%. Exelon has not provided any underlying rationale as to why the higher value assumed by the NYISO is a more reasonable approximation of the cost of capital for an investment in the New England market. Brattle’s analysis and rationale for its recommended approach has been presented and discussed extensively with the Markets Committee on a number of occasions. There are key differences that are important to note between the NYISO approach and the IMM’s proposal.

1. The NYISO’s cost of capital assumption is applicable to merchant investments without a long-term Power Purchase Agreement (“PPA”). The IMM proposed WACC is premised
on the assumption of a PPA for the energy output of the project over twenty years. Accounting for the PPA would lower the WACC.

2. The NYISO also recommended a 25 year life for the combined cycle and combustion turbines. Accounting for both the economic life as well as the WACC proposed by the NYISO, the ORTPs recommended by the IMM would not differ substantially from those calculated assuming a 7.2% WACC and 20-year life investment horizon.

Conclusion

The IMM believes that the methodology and stakeholder process used to update ORTPs, as well as the IMM’s decision not to calculate ORTPs for certain resource types and, instead, rely on asset-specific reviews is consistent with the Commission’s orders and the ISO’s FERC-approved tariff.
The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1 Offer Review Trigger Prices.
For each new technology resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price.

Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the Ninth Eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018 2017) shall be as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation Resources</strong></td>
<td></td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>$13.424</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.866</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$0.000</td>
</tr>
<tr>
<td><strong>Demand Resources - Commercial and Industrial</strong></td>
<td></td>
</tr>
<tr>
<td>Load Management</td>
<td>$1.145</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
<tr>
<td><strong>Demand Resources – Residential</strong></td>
<td></td>
</tr>
<tr>
<td>Technology Type</td>
<td>Offer Review Trigger Price ($/kW-month)</td>
</tr>
<tr>
<td>Load Management</td>
<td>$1.145</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>
### Load Management

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>

### Other Resources

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Forward Capacity Auction Starting Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>All other technology types</td>
<td>Forward Capacity Auction Starting Price</td>
</tr>
</tbody>
</table>

Where a new resource is composed of assets having different technology types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be $0.00/kW-month.

#### III.A.21.1.2 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project.
The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure programs’ life.

(d) For new Real-Time Demand Response Resources other than energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those using energy efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than energy efficiency Demand Resources) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs is based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger
Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Steam Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Wind Turbines</td>
<td>Bloomberg Wind Turbine Price Index</td>
</tr>
<tr>
<td>Other Equipment</td>
<td>BLS-PPI &quot;General Purpose Machinery and Equipment&quot;</td>
</tr>
<tr>
<td>Construction Labor</td>
<td>BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Other Labor</td>
<td>BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Materials</td>
<td>BLS-PPI &quot;Materials and Components for Construction&quot;</td>
</tr>
<tr>
<td>Electric Interconnection</td>
<td>BLS - PPI &quot;Electric Power Transmission, Control, and Distribution&quot;</td>
</tr>
<tr>
<td>Gas Interconnection</td>
<td>BLS - PPI “Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)”</td>
</tr>
<tr>
<td>Fuel Inventories</td>
<td>Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”</td>
</tr>
</tbody>
</table>

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor, Administrative and General</td>
<td>BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Materials and Contract Services</td>
<td>BLS-PPI &quot;Materials and Components for Construction&quot;</td>
</tr>
</tbody>
</table>
Site Leasing Costs | Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent twelve month period available at the time of making the adjustment divided by the average of the most recent twelve month period available at the time of establishing the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update through the end of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the twelve months following the time of the update, as published by the CME Group.

(5) Renewable Energy Credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2 New Resource Offer Floor Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward
Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant technology resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Real-Time Demand Response resource, the resource’s costs shall
include all expenses, including incentive payments, equipment costs, marketing and
selling and administrative and general costs incurred by the Demand Response Provider
and end-use customers to acquire the Real-Time Demand Response Resource. Revenues shall
include all non-capacity payments expected from the ISO-administered markets made for services
delivered from the Real-Time Demand Response Resource, and expected costs avoided by the
end-user customer as a direct result of the installation or implementation of the Demand Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New
Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to
participate, the relevant capital costs to be entered into the capital budgeting model will be the
undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing
market conditions will be those that were in place at the time of the decision to construct the
resource.

(iv) Sufficient documentation and information must be included in the resource’s
qualification package to allow the Internal Market Monitor to make the determinations
described in this subsection (b). Such documentation should include all relevant financial
estimates and cost projections for the project, including the project’s pro-forma financing
support data. For a new capacity resource that has achieved commercial operation prior to the
New Capacity Qualification Deadline, such documentation should also include all relevant
financial data of actual incurred capital costs, actual operating costs, and actual revenues since the
date of commercial operation. If the supporting documentation and information required by this
subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with
the Project Sponsor to gather further information as necessary to complete its analysis. If after
consultation, the Project Sponsor does not provide sufficient documentation and information for
the Internal Market Monitor to complete its analysis, then the resource’s New Resource Offer
Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is
consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s
New Resource Offer Floor Price shall be equal to the requested offer price.

(vi) If the Internal Market Monitor determines that the requested offer price is not
consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s
New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource’s qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.


For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource’s long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:
(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.
memo

To: Participants Committee

From: Alex Kuznecow, Secretary, Markets Committee

Date: November 15, 2013

Subject: ACTIONS OF THE MARKETS COMMITTEE

This memo is notification to the Participants Committee (PC) of the following actions taken by the Markets Committee (MC) at its November 13 and 14, 2013 meeting. All Sectors had a quorum.

1. (Agenda Item 1A) SEPTEMBER 20, 2013, OCTOBER 2, 2013 and OCTOBER 8 & 9, 2013 MC MEETING MINUTES

   ACTION: APPROVED

   It was moved, seconded and approved (with one abstention) by the Markets Committee on a show of hands to accept the minutes of the September 20th, October 2nd, and October 8th and 9th Markets Committee meetings.

2. (Agenda Item 2) FORWARD CAPACITY AUCTION #9 – OFFER REVIEW TRIGGER PRICES

   ACTION: MOTION FAILED

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Appendix A to Market Rule 1 implementing the proposed revisions to the Offer Review Trigger Prices (ORTP) for FCA #9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation (which must be addressed every third year) as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

(Vote 1 – Passed (EnerNOC Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Add a new Section III.13.1.4.2.4 to Market Rule 1 as follows:

   “III.13.1.4.2.4 Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers

   A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type.”

The motion to amend the main motion was then voted. The motion to amend passed with a vote of 68.86% in favor. The individual Sector votes were Generation (6.87% in favor, 10.3% opposed, 5
abstentions), Transmission (17.17% in favor, 0% opposed, 2 abstentions), Supplier (12.88% in favor, 4.29% opposed, 15 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (0.61% in favor, 16.56% opposed, 11 abstentions), and End User (17.17% in favor, 0% opposed).

(Vote 2 – Failed (NextEra Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Shore Wind</td>
<td>$0.00853</td>
</tr>
</tbody>
</table>

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 32.43% in favor. The individual Sector votes were Generation (15.26% in favor, 1.91% opposed, 1 abstention), Transmission (0% in favor, 17.17% opposed), Supplier (17.17% in favor, 0% opposed, 10 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed, 30 abstentions), and End User (0% in favor, 17.17% opposed).

(Vote 3 – Passed (Energy Management, Inc. Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 by adding Off-Shore Wind to the table as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off-Shore Wind</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

The motion to amend the amended main motion was then voted. The motion to amend passed with a vote of 68.12% in favor. The individual Sector votes were Generation (2.45% in favor, 14.72% opposed, 3 abstentions), Transmission (17.17% in favor, 0% opposed), Supplier (0% in favor, 17.17% opposed, 12 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (17.17% in favor, 0% opposed, 38 abstentions), and End User (17.17% in favor, 0% opposed, 2 abstentions).

(Vote 4 – Failed (Exelon Amendment)) Before the twice-amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the twice-amended main motion as follows:

1. Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>$13.42415.04</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.86610.18</td>
</tr>
</tbody>
</table>
The motion to amend the twice-amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 5 – Failed) The twice-amended main motion was then voted. The twice-amended main motion failed with a vote of 56.24% in favor. The individual Sector votes were Generation (1.91% in favor, 15.26% opposed, 1 abstention), Transmission (17.17% in favor, 0% opposed), Supplier (1.91% in favor, 15.26% opposed, 9 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 2 abstentions), Publicly Owned Entity (3.92% in favor, 13.25% opposed, 4 abstentions), and End User (17.17% in favor, 0% opposed).

3. (Agenda Item 2) FORWARD CAPACITY AUCTION #9 – OFFER REVIEW TRIGGER PRICES

ACTION: VOTE FAILED

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO’s proposed revisions to Appendix A to Market Rule 1 implementing the proposed revisions to the Offer Review Trigger Prices (ORTP) for FCA #9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation.

The Markets Committee action on the ISO’s proposed revisions to Appendix A to Market Rule 1 resulted in a vote of 16.57% in favor. The individual Sector votes were Generation (0.95% in favor, 16.22% opposed), Transmission (8.58% in favor, 8.59% opposed, 2 abstentions), Supplier (2.15% in favor, 15.02% opposed, 10 abstentions), Alternative Resources (4.28% in favor, 9.89% opposed, 3 abstentions), Publicly Owned Entity (0.61% in favor, 16.56% opposed, 11 abstentions), and End User (0% in favor, 17.17% opposed, 1 abstention).

4. (Agenda Item 3) NCPC LOCAL SECOND CONTINGENCY PROTECTION RESOURCE COST ALLOCATION

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Appendix F to Market Rule 1 to modify the cost allocation for Local Second Contingency Protection Resource requirements in the Day-Ahead Energy Market as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed with a vote of 80.61% in favor. The individual Sector votes were Generation (8.58% in favor, 8.59% opposed, 6 abstentions), Transmission (17.17% in favor, 0% opposed, 1 abstention), Supplier (6.36% in favor, 10.81% opposed, 16.3 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned
5. (Agenda Item 5) FUEL SWITCHING: USE OF REFERENCE LEVEL AS THE SUPPLY OFFER
ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1 to relocate the Appendix K to Market Rule 1 provisions to use a dual-fuel resource’s secondary fuel reference level as its supply offer following a fuel switch as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed. 6 abstentions within the Supplier Sector and 1 abstention within the Alternative Resources Sector were recorded.

6. (Agenda Item 6) DEMAND RESPONSE BASELINE AND OUTAGES
ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1 and Appendix E1 to Market Rule 1 to implement the Demand Resources Working Group recommended changes to the Demand Response Baseline to account for scheduled and forced curtailments of demand response assets as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed. 2 abstentions within the Generation Sector were recorded.

7. (Agenda Item 8) DEMAND RESOURCES WORKING GROUP (DRWG) REFERRAL REQUEST
ACTION: REFERRED TO WORKING GROUP

The following DRWG request was referred to the Demand Resources Working Group by the Markets Committee:

(1) Develop alternative auditing approach that addresses simultaneous RTDR-RTEG audit issue, and continues to avoid double-counting RTDR-RTEG capability.
8. (Agenda Item 13) NEPOOL GIS OPERATING RULES WORKING GROUP REFERRAL REQUEST
ACTION: REFERRED TO WORKING GROUP

The following NRG request was referred to the NEPOOL GIS Operating Rules Working Group by the Markets Committee:

(1) Consider potential revisions to Rule 2.6 of the NEPOOL GIS Operating Rules relating to changes in assignments of Certificates.

9. (Agenda Item 14) FCM PERFORMANCE INCENTIVES
ACTION: MOTION FAILED

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2 to implement the FCM Performance Incentives proposal and mitigation design as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

(Vote 1 – Failed (Brookfield Amendment #1)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7.2.4 of Market Rule 1 in accordance with the Brookfield proposed changes regarding Intermittent Power Resources (see Brookfield Amendment #1).

The motion to amend the main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 2 – Failed (Brookfield Amendment #2)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7.2.2 (b) of Market Rule 1 in accordance with the Brookfield proposed changes regarding Import Capacity Resources (see Brookfield Amendment #2).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 19.69% in favor. The individual Sector votes were Generation (0% in favor, 17.17% opposed, 3 abstentions), Transmission (0% in favor, 17.17% opposed, 1 abstention), Supplier (13.73% in favor, 3.44% opposed, 15 abstentions), Alternative Resources (5.47% in favor, 8.7% opposed, 4 abstentions), Publicly Owned Entity (0.49% in favor, 16.68% opposed, 2 abstentions), and End User (0% in favor, 17.17% opposed, 6 abstentions).
(Vote 3 – Failed (NextEra Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NextEra proposed changes (see NextEra Amendment).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 12.15% in favor. The individual Sector votes were Generation (2.15% in favor, 15.02% opposed, 2 abstentions), Transmission (0% in favor, 17.17% opposed), Supplier (5.72% in favor, 11.45% opposed, 14 abstentions), Alternative Resources (4.28% in favor, 9.89% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (0% in favor, 17.17% opposed, 4 abstentions).

(Vote 4 – Failed (MMWEC Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the MMWEC proposed changes (see MMWEC Amendment).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 49.35% in favor. The individual Sector votes were Generation (6.44% in favor, 10.73% opposed, 2 abstentions), Transmission (13.73% in favor, 3.44% opposed, 1 abstention), Supplier (8.58% in favor, 8.59% opposed), Alternative Resources (0% in favor, 14.17% opposed, 1 abstention), Publicly Owned Entity (17.17% in favor, 0% opposed), and End User (3.43% in favor, 13.74% opposed, 8 abstentions).

(Vote 5 – Passed (Brookfield Amendment #3)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7.2.4 of Market Rule 1 in accordance with the Brookfield proposed changes regarding ISO imposed limitations due to transmission and other system issues (see Brookfield Amendment #3).

The motion to amend the main motion was then voted. The motion to amend passed with a vote of 71.77% in favor. The individual Sector votes were Generation (15.02% in favor, 2.15% opposed, 2 abstentions), Transmission (8.58% in favor, 8.59% opposed), Supplier (17.17% in favor, 0% opposed, 12 abstentions), Alternative Resources (14.17% in favor, 0% opposed), Publicly Owned Entity (2.52% in favor, 14.65% opposed, 5 abstentions), and End User (14.31% in favor, 2.86% opposed, 1 abstention).

(Vote 6 – Failed (NU Amendment #3)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Add a new Section III.13.7.2.7 to Market Rule 1 as follows:

“III.13.7.2.7 Exception.
(a) A resource’s Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver energy or reserves during that Capacity Scarcity Condition is due to an outage or de-rate of a transmission facility in the New England Control Area that is beyond the control of the resource.”

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 42.06% in favor. The individual Sector votes were Generation (3.43% in favor, 13.74% opposed), Transmission (17.17% in favor, 0% opposed), Supplier (0% in favor, 17.17% opposed, 11 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 2 abstentions), Publicly Owned Entity (17.17% in favor, 0% opposed, 34 abstentions), and End User (4.29% in favor, 12.88% opposed, 5 abstentions).

(Vote 7 – Failed (EquiPower Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Add a new Section III.13.1.2.3.2.4.1 to Market Rule 1 as follows:

III.13.1.2.3.2.4.1 Static De-List Bids for Reductions in Ratings Due to EFORd

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects may not be physically available due expected unavailability represented by EFORd times summer Qualified Capacity at 90 degrees. EFORd shall be the value, as reported through GADS, for the most recent Capacity Commitment Period prior to time at which the FCM qualification process takes place. The ISO shall verify during the qualification process that the value is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.”

The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 8 – Failed (GDF SUEZ Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the GDF SUEZ proposed changes (see GDF SUEZ Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 45.12% in favor. The individual Sector votes were Generation (17.17% in favor, 0% opposed), Transmission (0% in favor, 17.17% opposed, 2 abstentions), Supplier (17.17% in favor,
0% opposed, 7 abstentions), Alternative Resources (5.88% in favor, 8.29% opposed), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (4.91% in favor, 12.26% opposed, 6 abstentions).

(Vote 9 – Failed (GDF SUEZ Alternative Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the GDF SUEZ proposed changes (see GDF SUEZ Alternative Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 45.16% in favor. The individual Sector votes were Generation (17.17% in favor, 0% opposed, 1 abstention), Transmission (0% in favor, 17.17% opposed, 2 abstentions), Supplier (17.17% in favor, 0% opposed, 7 abstentions), Alternative Resources (10.83% in favor, 3.34% opposed, 2 abstentions), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (0% in favor, 17.17% opposed, 10 abstentions).

(Vote 10 – Failed (NU Amendment #1)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NU proposed changes regarding passive demand resources (see NU Amendment #1).

The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 11 – Failed (NU Amendment #2)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NU proposed changes regarding existing generation (see NU Amendment #2).

The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 12 – Failed (Dominion Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Replace the ISO FCM Performance Incentives proposal with revisions to existing Sections III.13.1, III.13.2, III.13.3, III.13.4, III.13.5 and III.13.8 of Market Rule 1, and the addition of a new Section III.13.7.3.1 to Market Rule 1 in accordance with the Dominion proposed changes (see Dominion Amendment).
The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 21.74% in favor. The individual Sector votes were Generation (11.44% in favor, 5.73% opposed, 4 abstentions), Transmission (0% in favor, 17.17% opposed), Supplier (10.3% in favor, 6.87% opposed, 15 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 2 abstentions), Publicly Owned Entity (0% in favor, 17.17% opposed, 2 abstentions), and End User (0% in favor, 17.17% opposed, 3 abstentions).

(Vote 13 – Failed (NRG Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Replace the ISO FCM Performance Incentives proposal with revisions to existing Sections III.13.1, III.13.2, III.13.4, III.13.7 and III.13.8 of Market Rule 1 in accordance with the NRG proposed changes (see NRG Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 31.65% in favor. The individual Sector votes were Generation (12.88% in favor, 4.29% opposed, 4 abstentions), Transmission (0% in favor, 17.17% opposed, 1 abstention), Supplier (17.17% in favor, 0% opposed, 12 abstentions), Alternative Resources (1.6% in favor, 12.57% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed, 10 abstentions), and End User (0% in favor, 17.17% opposed, 5 abstentions).

(Vote 14 – Failed) The amended main motion was then voted. Based on a show of hands, the amended main motion failed.

10. (Agenda Item 14) FCM PERFORMANCE INCENTIVES
ACTION: VOTE FAILED

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO’s proposed revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2 to implement its FCM Performance Incentives proposal and mitigation design.

Based on a show of hands, the Markets Committee failed to support the ISO’s proposed revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2.
MOPR Amendment
November 13, 2013
Agenda

• Background

• Problem Statement

• Solution
Goals

• This amendment will:
  
  • Provide greater certainty to all market participants than currently exists in the tariff
  
  • Be consistent with the objectives of the MOPR
  
  • Recognize the unique situation faced by Demand Response Capacity Resources
Background: DR Products and Measure Types

Demand Response Capacity Resources can have customers that either employ Load Management or Distributed Generation to meet their reduction plan.
Background

• When a Demand Resource completes their SOI and their new qualification package, they have to select one or more measure types for that resource (energy efficiency, load management, distributed generation)

• Currently there is no clear Market Rule that prohibits a Demand Resource from selecting one measure type during qualification and eventually registering a customer with a different measure type for the delivery year, although ISO says its not allowed in the QDN

• ISO cites III.13.1.4.2.3 “Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form”:

“The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: .... (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation);”
Problem Statement

• Given that ISO is now proposing different ORTPs for each measure type (EE, DG, and load management), there needs to be clear tariff language that addresses this issue so all parties can proceed with certainty

• That language should support the goals of the MOPR but not ignore the reality that Demand Response Capacity Resources (DRCR) have different characteristics than other demand resources and generation resources

• For other demand resources (and generation), the Project Sponsor knows during qual what measure/technology type will be employed by the assets in that resource

• However, the project sponsors for DRCR are not certain during qual whether load management or distributed generation will be used by the assets in the resource

• Four years before the delivery year a CSP has completed a market potential analysis but its customer base is far from finalized
Problem Statement Cont’d and Solution

• Going forward, DG is unlikely to be used as a measure type by a DRCR

• Therefore the Project Sponsor for a DRCR would almost definitely check the “Load Management” box during qualification

• However, if a DRCR owner finds a customer with DG, that customer should be allowed to be registered as long as it didn’t receive out-of-market revenues associated with the installation and delivery of that DG. System Planning says there are no reliability reasons to prevent that customer from being registered

• Solution: When registering the customer with a different measure type, the resource owner will have to verify that no out-of-market revenues were received. Out-of-market revenues are very public which addresses any concerns about concealment

• NYISO accounts for out-of-market revenues in the resource’s offer floor price
III.13.1.4.2.4 Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers

A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type.
Appendix Slide

NYISO MST 23, Attachment H, 23.4.5.7.5:

“The Offer Floor for a Special Case Resource shall be equal to the minimum monthly payment for providing Installed Capacity payable by its Responsible Interface Party, plus the monthly value of any payments or other benefits the Special Case Resource receives from a third party for providing Installed Capacity, or that is received by the Responsible Interface Party for the provision of Installed Capacity by the Special Case Resource.”
III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4 Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers

A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type
ORTP Proposal for On-Shore Wind

Michelle C. Gardner
NextEra Energy Resources

Markets Committee
November 13-14, 2013
The April 13, 2011 FERC Order Required ISO-NE to Implement an Effective FCM Offer Price Floor Mechanism

- “Entities with buyer-side market power can artificially lower the capacity price, sometimes substantially, by subsidizing new investment that is then offered into the market at prices below its full entry costs.”

- “…if the offer floor is set at a level that approximates the net cost of entry of a new resource, offer-floor mitigation would deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry. By preventing new resources from offering at prices that are significantly below their true net cost of new entry, new resources would not be able to lower the price of capacity significantly below competitive levels.

- “Accordingly, we will require ISO-NE to address offer-floor mitigation through the stakeholder process…. Specifically, this stakeholder process should develop tariff revisions to implement buyer-side mitigation in the FCM that would impose offer floors on new resources offering into the FCM auctions.”
ISO-NE proposed “Offer Review Trigger Prices” in New England in order to determine when a resource’s proposed FCA Offer Price needs to be reviewed.

**Offer Review Trigger Prices**

- Series of benchmark prices for various resource types
- Resources can offer in FCA at prices equal to or greater than its ORTP with no IMM cost review
- If ORTP is not a hard floor below which a resource cannot offer
- Resources requesting to remain in FCA below its trigger price must submit resource-specific cost data to IMM for evaluation.
- IMM evaluation is to make sure that resource’s offer into the FCM will be competitive, consistent with the goals of the offer floor mechanism the Commission required in the April 13, 2011 FERC order.
IMM has proposed to modify the ORTP for all on-shore wind resources from $14/kW-month to $0/kW-month in one year, effectively stating that the IMM will no longer review any offers from such resources

**Offer Review Trigger Prices**

- With an ORTP of $0/kw-month, no on-shore wind resources will have their offer prices reviewed.
- Having an on-shore wind ORTP of $0/kw-month is inconsistent with the goal of having the ORTP protect against the potential for inappropriate (or inefficient) price suppression.
Five Factors caused the On-Shore Wind ORTP Proposed by IMM to change from the $9.87/kW proposed in August 2013

Offer Review Trigger Prices

- Capacity Factor increased
- Qualified Capacity increased
- REC revenue offset increased
- Interconnection costs decreased
- Depreciation Schedule changed

Of these, Capacity Factor is a big driver of the change.
IMM Proposal Pushes Capacity Factor to 35% even though its own analysis only reaches 31%

**Capacity Factor for On-Shore Wind Resources**

IMM has proposed a capacity factor of 35% for on-shore wind resources, based on several stated factors:

- Historical analysis of wind farms in operation for over 6 months with a capacity factor greater than 25% - weighted average capacity factor of wind farms meeting this criteria equals 31%
- Non-public IMM asset-specific reviews
- Assertion of prospective improvements in technology
- Input from IMM’s contractor, Sargent & Lundy
- The IMM conducted a sensitivity analysis of the ORTP to Capacity Factor Assumptions
IMM Proposal is biased too high based on an arbitrarily chosen small sample size

**Capacity Factors**

The IMM reviewed only four on-shore wind resources with capacity factors greater than 25% (see orange highlighted entries on next slide)

- One in Massachusetts, One in New Hampshire, and Two in Maine
- Includes Wind Turbine Unit Sizes from 1.5MW to 2.0MW
- Includes Resources with Commercial Operation Dates from September 2008 to December 2011

Publicly available EIA data indicates that there are 22 on-shore wind resources that could have been considered by ISO

- Good geographical distribution across New England (all except CT)
- Includes Wind Turbine Unit Sizes from 0.55MW to 3.0MW
- Includes Resources with Commercial Operations Dates: July 1997 to May 2012 (most from 2008 on)

**NOTE:** In table on following page, cells highlighted in rose-color have been excluded from analysis due to either: (i) insufficient operating history – less than 6-months; or (ii) known significant operating problems stated in press reports.
Operating On-Shore Wind Resources in New England as Reported in EIA-923 and EIA-860 Reports for 2011 and 2012

<table>
<thead>
<tr>
<th>Plant Id</th>
<th>Plant Name</th>
<th>Region</th>
<th>In-Service Date</th>
<th>Location</th>
<th>Turbine Manufacturer</th>
<th>Turbine Unit Size (MW)</th>
<th>Station Nameplate Capacity (MW)</th>
<th>2011 Capacity Factor</th>
<th>2012 Capacity Factor</th>
<th>2011 Weighted Average Annual Capacity Value Factor</th>
<th>2012 Weighted Average Annual Capacity Value Factor</th>
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<tr>
<td>57721</td>
<td>Berkshire Wind Power Project</td>
<td>Far Western MA</td>
<td>May-11</td>
<td>Hancock, MA</td>
<td>GE</td>
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<td>Beaver Ridge Wind</td>
<td>Inland Central Coast ME</td>
<td>Oct-08</td>
<td>Freedom, ME</td>
<td>GE</td>
<td>1.50</td>
<td>4.5</td>
<td>29.62%</td>
<td>32.48%</td>
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<td>Southwestern ME</td>
<td>Dec-11</td>
<td>Windham, ME</td>
<td>Gamesa</td>
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<td>Mars Hill, ME</td>
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<td>Nobska Wind 1 Cape Cod MA</td>
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<td>Falmouth, MA</td>
<td>Vestas</td>
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<td>Southwestern NH</td>
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<td>Lampeter Mountain, NH</td>
<td>Gamesa</td>
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<td>Cape Cod MA</td>
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<td>US Air Base, Falmouth, MA</td>
<td>Gamesa</td>
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<td>Northern VT</td>
<td>Jul-11</td>
<td>Burlington, Lk. and HR</td>
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<td>60.0</td>
<td>24.10%</td>
<td>24.10%</td>
<td>21.2%</td>
<td></td>
</tr>
<tr>
<td>35398</td>
<td>Searsburg Wind Turbine</td>
<td>Southwestern VT</td>
<td>Jul-91</td>
<td>Searsburg, VT</td>
<td>GE</td>
<td>0.35</td>
<td>5.0</td>
<td>20.60%</td>
<td>23.16%</td>
<td>11.12%</td>
<td></td>
</tr>
<tr>
<td>57089</td>
<td>Shedd Wind</td>
<td>Northeastern VT</td>
<td>Oct-11</td>
<td>Shedd, VT</td>
<td>Clipper Liberty</td>
<td>2.50</td>
<td>20.5</td>
<td>19.08%</td>
<td>21.08%</td>
<td>16.5%</td>
<td></td>
</tr>
<tr>
<td>58405</td>
<td>Kiddy Wind Power Project</td>
<td>Far Western Central ME</td>
<td>Sep-06</td>
<td>Mountain, North Franklin</td>
<td>Vestas</td>
<td>3.00</td>
<td>132.0</td>
<td>24.08%</td>
<td>22.78%</td>
<td>20.85%</td>
<td></td>
</tr>
<tr>
<td>56699</td>
<td>Station Wind 1 Northeast VT</td>
<td>Dec-08</td>
<td>Mountain, North Franklin</td>
<td>GE</td>
<td>1.50</td>
<td>35.5</td>
<td>30.51%</td>
<td>27.46%</td>
<td>22.52%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>57654</td>
<td>Town of Falmouth WWTP Cape Cod MA</td>
<td>Feb-10</td>
<td>Falmouth, MA</td>
<td>Vestas</td>
<td>1.65</td>
<td>1.7</td>
<td>18.03%</td>
<td>18.03%</td>
<td>5.33%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>57399</td>
<td>Station Wind II Northeast VT</td>
<td>Mar-10</td>
<td>Mountain, North Franklin</td>
<td>GE</td>
<td>1.50</td>
<td>20.5</td>
<td>28.15%</td>
<td>28.15%</td>
<td>15.7%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>58004</td>
<td>Granite Reliable Power</td>
<td>Northern NH</td>
<td>Feb-12</td>
<td>White Mountain, Stark NH</td>
<td>Vestas</td>
<td>3.00</td>
<td>99.0</td>
<td>18.25%</td>
<td>14.8%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10823</td>
<td>Deer Island Treatment Plant</td>
<td>Coastal MA</td>
<td>Nov-09</td>
<td>Boston Harbor</td>
<td>Elicon</td>
<td>0.60</td>
<td>1.2</td>
<td>15.63%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7501</td>
<td>Princeton Wind Farm</td>
<td>Central MA</td>
<td>Sep-09</td>
<td>Princeton, MA</td>
<td>Turbines</td>
<td>1.80</td>
<td>3.5</td>
<td>35.0%</td>
<td>35.0%</td>
<td>12.0%</td>
<td></td>
</tr>
<tr>
<td>56963</td>
<td>Hale Hill Wind Project</td>
<td>Inland Northern Coast ME</td>
<td>Oct-06</td>
<td>Township 16, ME</td>
<td>Vestas</td>
<td>1.80</td>
<td>34.5</td>
<td>38.56%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>56890</td>
<td>Charlestown Wind Turbine</td>
<td>Coastal MA</td>
<td>Nov-11</td>
<td>Charlestown, MA</td>
<td>Vestas</td>
<td>1.50</td>
<td>1.5</td>
<td>22.16%</td>
<td>14.68%</td>
<td>7.7%</td>
<td></td>
</tr>
<tr>
<td>57979</td>
<td>Kingdom Community Wind</td>
<td>Far Northern VT</td>
<td>Dec-12</td>
<td>Lowell, VT</td>
<td>Vestas</td>
<td>3.00</td>
<td>63.0</td>
<td>2.25%</td>
<td>2.25%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>54184</td>
<td>New England Wind LLC</td>
<td>Far Northern ME</td>
<td>Dec-12</td>
<td>Monroe &amp; Florida, MA</td>
<td>GE</td>
<td>1.50</td>
<td>28.5</td>
<td>3.79%</td>
<td>3.79%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>56143</td>
<td>Grenville Wind LLC</td>
<td>Central NH</td>
<td>Dec-12</td>
<td>Grinston, NH</td>
<td>Gamesa</td>
<td>2.00</td>
<td>48.0</td>
<td>22.5%</td>
<td>22.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>58390</td>
<td>New England Community Wind Farm</td>
<td>Far Northwestern VT</td>
<td>Dec-12</td>
<td>George and Milton, VT</td>
<td>Goldwind America</td>
<td>2.50</td>
<td>48.0</td>
<td>22.5%</td>
<td>22.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>57350</td>
<td>Portsmouth Wind Turbine</td>
<td>Coastal RI</td>
<td>Mar-09</td>
<td>Portsmouth, RI</td>
<td>GE</td>
<td>1.50</td>
<td>1.5</td>
<td>22.16%</td>
<td>0.01%</td>
<td>11.0%</td>
<td></td>
</tr>
</tbody>
</table>

Note: Less than 6 months operation
- Foundation Problem
- Gear Box Problem
Data Should Start with all 22 On-Shore Wind Resources

Wider Sample Size Indicates ORTP of $38.29/kW

A consistent set of publicly-available data should be used

IMM should consider all available resources, except those with insufficient operations (e.g. <6-months) or known “extraordinary” problems (e.g., gearbox failure or foundation problem)

• Using this criteria would result in a Average Capacity Factor of 25.01%, a Annual Capacity Value of 15.66% and a ORTP of $38.29/kW-month
Limiting the data set to resources with recent commercial operation dates also produces a high ORTP

Even Recent Vintage Supports High ORTP of $26.21

Limiting criteria to resources with Commercial Operations Dates between May 2011 and May 2012

- Sensitive to IMM statements that it wants to capture asserted improvements in technology
- Includes 8 resources *(highlighted in blue on slide 8)*
- Appears to have good geographical distribution across New England (4 out of the 6 NE states)
- Includes Wind Turbine Unit Sizes from 1.5MW to 3.0MW

Using this criteria would result in a Average Capacity Factor of 25.65%, an Annual Capacity Value of 20.52% and a ORTP of $26.21/kW-month
Limiting the data set using the IMM’s own criteria of “greater than 25% capacity factor” is proposed

**NextEra Proposal for ORTP of $8.53**

The weighted average capacity factor of on-shore wind farms with a capacity factor greater than 25% equals 29.74%, which is close to the IMM’s 31% *(highlighted in yellow on slide 8)*

- Includes 10 currently operating wind projects in New England
- Appears to have good geographical distribution across New England
- Includes Wind Turbine Unit Sizes from 1.5MW to 2.3MW
- Includes Resources with Commercial Operations Dates: October 2006 to January 2012
- Captures 3 of the 4 wind resources utilized by the IMM

Using this criteria would result in a Average Capacity Factor of 29.74%, an Annual Capacity Value of 16.82% and a ORTP of $8.53/kW-month
## Summary of Capacity Factors and Annual Capacity Values Used in Analysis

**Based On 2012 EIA Data**

<table>
<thead>
<tr>
<th>Capacity Factor</th>
<th>Annual Capacity Value</th>
<th>Resulting On-Shore Wind ORTP ($/kw-mo)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>36.25%</td>
<td>27.63%</td>
</tr>
<tr>
<td>Minimum</td>
<td>15.18%</td>
<td>1.32%</td>
</tr>
<tr>
<td>Median</td>
<td>24.68%</td>
<td>16.10%</td>
</tr>
<tr>
<td>Average</td>
<td>25.01%</td>
<td>15.66%</td>
</tr>
<tr>
<td>Average 2011/12 Vintage</td>
<td>25.65%</td>
<td>20.52%</td>
</tr>
<tr>
<td>Average Resources with CF&gt;25%</td>
<td>29.74%</td>
<td>16.82%</td>
</tr>
</tbody>
</table>

**Average Resources with CF>25%**: $8.53
NextEra Amendment

Amend Section III.A.21.1.1 “Offer Review Trigger Prices for the Ninth Forward Capacity Auction” of the ISO-NE Tariff as follows:

– Change the Offer Review Trigger Price for On-Shore Wind from $0/kW-month to $8.53/kW-month

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1  Offer Review Trigger Prices.

For each new technology resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price.

Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.


For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the Ninth/Eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 20182017) shall be as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation Resources</td>
<td></td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>$13.42416</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.754866</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$9.870.0670</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demand Resources - Commercial and Industrial</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable Load Management</td>
<td>$1.1455</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>

| Demand Resources – Residential               |                                        |

**NEPOOL PARTICIPANTS COMMITTEE**
**DEC. 6, 2013 MEETING, AGENDA ITEM #9**
**Attachment D**
<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable Load Management</td>
<td>$7.094</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>

**Other Resources**

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>$10.00</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$11.00</td>
</tr>
<tr>
<td>Biomass</td>
<td>$24.00</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$14.00</td>
</tr>
<tr>
<td>Real-Time Demand Response</td>
<td>$1.00</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.00</td>
</tr>
<tr>
<td>All Other Resource Types</td>
<td>Forward Capacity Auction Starting Price</td>
</tr>
</tbody>
</table>

Where a new resource is composed of assets having different technologyresource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technologyresource type of the External Resource.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be $0.00/kW-month.

**III.A.21.1.2 Calculation of Offer Review Trigger Prices.**

(a) The Offer Review Trigger Price for each of the technologyresource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting
model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measures’ life.

(d) For new Real-Time Demand Response Resources other than energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those using energy efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than energy efficiency Demand Resources) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs. The incremental cost is then divided by the incremental MW to estimate the incremental cost.
revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Steam Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Wind Turbines</td>
<td>Bloomberg Wind Turbine Price Index</td>
</tr>
<tr>
<td>Other Equipment</td>
<td>BLS-PPI &quot;General Purpose Machinery and Equipment&quot;</td>
</tr>
<tr>
<td>Construction Labor</td>
<td>Composite index developed from RS Means labor categoriesBLS &quot;Quarterly Census of Employment and Wages&quot; 2371 Utility System Construction Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Other Labor</td>
<td>Composite index developed from BLS job classificationsBLS &quot;Quarterly Census of Employment and Wages&quot; 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Materials</td>
<td>BLS-PPI &quot;Materials and Components for Construction&quot;</td>
</tr>
<tr>
<td>Electric Interconnection</td>
<td>BLS - PPI &quot;Electric Power Transmission, Control, and Distribution&quot;BLS-PPI &quot;Electric Power Distribution&quot;</td>
</tr>
<tr>
<td>Gas Interconnection</td>
<td>BLS - PPI &quot;Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)&quot;BLS-PPI &quot;Oil and Gas Field Machinery and Equipment&quot;</td>
</tr>
<tr>
<td>Fuel Inventories</td>
<td>Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”</td>
</tr>
</tbody>
</table>

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor, Administrative and General</td>
<td>BLS &quot;Quarterly Census of Employment and Wages&quot; 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
</tbody>
</table>
Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts
On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine

Materials and Contract Services
BLS-PPI "Materials and Components for Construction"

Site Leasing Costs
Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(32) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent twelve month period available at the time of making the adjustment divided by the average of the most recent twelve month period available at the time of establishing values included in the capital budgeting model used to establish the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(43) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by a multiplier calculated by using inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update that corresponds through to the end first year of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the twelve months following the time of the update, as published by NYMEX the CME Group divided by the Henry Hub natural gas price used in the capital budgeting model.

(54) Renewable Energy Credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest that corresponds to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(65) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(76) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2 New Resource Offer Floor Prices.
For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall
determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant technology resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation
and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new **Real-Time Demand Response** resource, the resource’s costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider and end-use customers to acquire the **Real-Time Demand Response** resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the **Real-Time Demand Response** resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource’s qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project’s pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource’s New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be equal to the requested offer price.
(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource’s qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.


For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource’s long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.
(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity
Auction:

(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation
continue to apply for more than one Capacity Commitment Period made pursuant to
Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning
of the Capacity Commitment Period associated with the eighth FCA (beginning June 1,
2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have
never been previously counted as capacity, such that it meets the definition, and must
meet the requirements, of a new capacity resource for the subsequent Forward Capacity
Auction in which it seeks to participate.
To: Markets Committee

October 4, 2013

Re: ORTP for Offshore Wind

At the September MC meeting, we raised the objection that the ISO’s revised Technology Screening Analysis (which calculated an Offer Review Trigger Price (“ORTP”) for offshore wind of $17) was based upon an unrealistically low capacity factor (“CF”) input of 37%. In contrast, ISO utilizes a 45.2% CF input in its calculation of offshore wind energy revenue margins, based upon the National Renewable Energy Laboratory’s (NREL’s) region-specific offshore wind production data. ISO asked that we provide public, third-party information to support our claim.

**Our September 13 Letter to ISO-NE.** Our letter of September 13 documented extensive evidence indicating a 2018 offshore CF of 45% or more (i.e., the same CF utilized by ISO in its own energy price calculation), including the region-specific analysis of both the U.S. NREL and academic experts, and as supported by data from the actual and recent European experience.

**Our September 19 Letter to ISO-NE.** Although we did not challenge ISO’s capital cost inputs, at their request for additional information on costs, we submitted a letter of September 19 in which we provided extensive public data confirming capital costs lower than those assumed by ISO, including the current cost estimation from NREL’s “Energy Data for Decision Makers” and an extensive cost analysis conducted by the U.S. Bureau of Ocean Energy Management (BOEM, the federal agency primarily responsible for leasing offshore wind) based upon the actual capital costs of existing projects, including the most recent utility-scale projects.

**Our September 27 Letter.** In response to ISO’s request for further explanation of the data behind BOEM’s capital cost analysis and “bottom up” cost data, we responded with a letter of September 27, which explained that the BOEM study was based upon actual cost information of 32 projects and that “wind farms were eliminated from the analysis if there was no reliable information about their costs,” and included a reference case of 18 post-2005 projects. All cases showed capital costs less than those shown in the ISO model. We further explained that the BOEM study confirmed its conclusions by referencing a 37 page Ernst &Young “bottom up” study conducted for the U.K. government that calculated total capital costs of offshore wind as the sum of its capital cost components, utilizing public, proprietary and governmental cost data, and separately analyzing current and future component costs of turbines, foundations, electrical infrastructure and development cost. Notably, BOEM concluded that the bottom-up analysis validated its own actual costs analysis. Our letter also offered to provide any further
information that would be useful, and none was requested.

**ISO’s October 3 MC Materials.** ISO now states that it does not intend to propose an ORTP for offshore wind, claiming it has “insufficient detailed data to conduct a bottom-up analysis,” notwithstanding the extensive actual cost information provided and the bottom-up analysis relied upon by the responsible agencies of both the U.S. and U.K. governments, and the fact that we do not challenge ISO’s capital cost input to the economic model. We protest the ISO decision and ask them to set an ORTP “equal to the one-year capacity price output of the model” with a corrected CF input of 45%, i.e., the same CF input that ISO uses for its own energy price calculation. Lack of an ORTP based upon inputs reflecting best available data would violate the tariff and place offshore wind on an un-level playing field versus other technologies, which could make investment decisions with superior advance knowledge of permitted bidding parameters.

Sincerely,

Dennis J. Duffy, V.P.
September 13, 2013

Sam Newell
The Brattle Group, Inc.
44 Brattle St #44
Cambridge, MA 02138
(617) 864-7900

Re: Analysis of ORTP Offshore Wind Assumptions

Dear Mr. Newell,

We have examined the latest version of the Technology Screening Analysis of the ISO-NE ORTP 2013 Study and wish to point out instances where the assumed 2018 values for offshore wind resources are not in accord with the prevailing view of objective public sources, including the region-specific analyses conducted for those offshore resources and technologies that would be directly applicable to the 2018 FCA, as well as the actual performance of offshore wind projects operating in Europe. Further, the rapid and continuing advance of offshore technology, including larger, more efficient machines and increased rotor lengths, substantially improves the performance that would be applicable to a 2018 market entry. Most importantly, the weight of objective data supports a 2018 capacity factor (CF) of not less than 45% for offshore wind projects off the coast of New England. Set forth below are multiple examples of objective sources that would conservatively support a 2018 offshore wind capacity factor of 45% or higher, including data specifically applicable to the New England control area.

I. New England Offshore Wind Capacity Factor for 2018

a. NREL’s Current Data Platform Indicates a Median 2018 CF of 46.6% for Offshore Wind.

The National Renewable Energy Laboratory (NREL) is the U.S. Department of Energy’s primary national laboratory for the study and advancement of renewable energy and its principal source of expertise in such matters, including both onshore and offshore wind energy. As part of its Energy Data for Decision Makers, NREL has developed Open Energy Information (“Open EI”), a public data platform maintained in conjunction with the DOE that “catalyzes the world’s energy information and links data together in new ways” and that is specifically intended to “expand decision-making capabilities.” According to the currently posted assessment in the Transparent Cost Database on Open EI, offshore wind capacity factors for 2018 will have a median value of 46.6%, as set forth in the NREL chart below, a copy of which is attached as Appendix A."
b. NREL’s Region-Specific Analysis Indicates a CF of 46.6%–47.4% for Offshore Wind in New England.

Moreover, with specific reference to the offshore wind resources applicable to NEPOOL, NREL in April of 2013 published a technical report, attached hereto as Appendix B entitled “Analysis of Offshore Wind Energy Leasing Areas for the Rhode Island / Massachusetts Wind Energy Area,” which concluded that the best available data indicates capacity factors of 46.6% and 47.4% for potential lease areas off the New England coast. Such study was conducted in cooperation and under an interagency agreement with the United States Bureau of Ocean Energy Management (“BOEM”), the federal agency with primary responsibility for the development, leasing and oversight of wind energy resources on the Outer Continental Shelf of the United States. The report was based upon extensive multi-year meteorological data evaluated with sophisticated modeling and three-dimensional wind flow mapping. Id. at 8. The capacity factor conclusions of the report are set forth in the following Table 5 of such report:
Id. at 17. We are further advised that NREL is currently preparing a similar technical report for the Massachusetts Wind Energy Area (a tract south of the Islands of Martha’s Vineyard and Nantucket that would also be of specific relevance to the New England control area) that NREL expects to show even higher capacity factors, as the data indicates wind speeds of this additional lease area are higher than for the RI/MA lease area.

c. Academic Analysis Indicates CFs of 45-50% for Offshore New England.

A similar region-specific conclusion was reached by the attached academic report, attached hereto as Appendix C, entitled “Where is the ideal location for a US East Coast offshore grid?,” published in Volume 39, Issue 6, of Geophysical Research Letters, March, 2012 (a peer-reviewed scientific publication of the American Geophysical Union) and authored by five researchers at Stanford University and the University of Delaware, with support from the U.S. EPA and the NASA Advanced Supercomputing Division.iii The study analyzed “high-resolution meso-scale model data” with sophisticated weather forecasting models, with hourly model inputs verified with weather buoy and tower data from 2006 to 2010. Id. at 2. The survey sought to identify the offshore wind sites off the coast of the Mid-Atlantic and New England states that would “provide the highest overall and peak-time summer capacity factor,” and determined that areas offshore of the states of Massachusetts, Rhode Island, and New York had the best capacity factors, noting: “The improved peak-time summer resource near the coast is primarily due to sea breezes that develop in this region”. Id. at 3. The study also noted “sites likely to have sea breezes (e.g., Long Island and Nantucket Sound) helped increase the peak-time capacity factor during the spring and summer months.” Id. at 5. In addition, the study found that eleven of the twelve offshore wind sites had capacity factors above 45% and that three sites had annual capacity factors at or above 50% (Figure 2). Further, with specific respect to New England resources relevant to NEPOOL, the top five offshore sites indicated annual CFs greater than 45%, and three (MV, RIS2, and NS) indicated annual CFs of 50%, as set forth below in the Figure 2 of Report (Id. at 3):
d. **Empirical data from Europe Confirms Offshore CFs in excess of 45%.**

Reference to the decades of actual experience of numerous existing offshore wind projects confirms the foregoing CF conclusions. Attached as Appendix D is a recent article published on August 15, 2013 entitled “Capacity Factors at Danish Offshore Wind Farms” setting forth actual project-specific performance data provided by the Danish Energy Agency. As set forth therein, the 2012 capacity factor for Denmark’s entire fleet of offshore wind farms was 44.9%, while the lifetime capacity factor for Denmark’s fleet of offshore wind farms was 39.1%. (It is important to note that the Danish fleet includes several near-shore demonstration projects and some of the oldest offshore wind farms in the world — six of the wind farms are less than 25 MWs, including Vindby, which was built in 1991 and thus utilized twenty-year old technology, and Tunø Knob, which is over 17 years old). The most relevant Danish capacity factor data are from utility-scale projects built since 2009, Horns Rev II, which had a 2012 capacity factor of 52%, and Nysted (Redsand) 2, which had a 2012 capacity factor of 45.9%; taken together these two facilities had an average capacity factor in 2012 of approximately 49% and an average lifetime capacity factor of 46.5%, as indicated in the following table:
September 13, 2013
Page 6

intends to lease multiple sites off the New England coast in the near future, for which the latest NREL analyses specifically confirm the higher projected CFs.) Also compelling are the actual CFs achieved by operating offshore wind projects utilizing existing technology (i.e., with no allowance for expected technological advances), for which there is ample empirical data, with demonstrated CFs of 45.9% and 52% for projects coming on line since 2009. In conclusion, we believe that the foregoing information justifies a 2018 CF for offshore wind in New England of 45% or higher, and would welcome the opportunity to meet and discuss these and other study assumptions further. v

Sincerely,

Dennis J. Duffy, Vice President

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v As previously indicated, we have concerns over certain other study assumptions, including whether there is appropriate recognition of the superior on-peak performance (and thus Average Electric Price) of offshore wind in New England, a factor that has been recognized by the adjudicatory decision of the Massachusetts Department of Public Utilities in MDPU Order 10-54, Petition of Massachusetts Electric Co. (2010)”We find that the evidence put forth by National Grid and other parties regarding the [offshore] facility’s projected capacity relative to land-based wind is extensive and credible and, based on this evidence, we conclude that he facility will contribute to meeting system peak load requirements.” Id. at 199.) We thank you for the recently supplied data relative to such issue, which we will review promptly.

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i http://www.nrel.gov/analysis/energydata.html
ii http://en.opencore.org/apps/TCDB/
September 19, 2013

Sam Newell
The Brattle Group, Inc.
44 Brattle St #44
Cambridge, MA 02138
(617) 864-7900

Re: Further Analysis of the 2018 Assumed Offshore Wind Factors

Dear Mr. Newell,

In our letter of September 13 regarding the recently revised Technology Screening Analysis utilized in the ISO-NE ORTP 2013 Study we pointed out that the assumed 2018 capacity factor for offshore wind resources is not in accord with the prevailing view of objective public sources, which would conservatively support a 2018 offshore wind capacity factor of 45% or higher applicable to the New England control area. After contacting Mr. Haggerty today, it seems that additional information confirming capital cost information would be helpful. While we have not challenged your capital cost assumptions, as set forth below, there is a wealth of public and objective information (based upon both actual costs of 32 offshore wind projects and current agency projections) that supports cost assumptions at levels below those presumed in the latest version of the Screening Analysis, and which is as reliable as data on other technologies. Thus, access to capital cost data is not a valid rationale for not setting an appropriate 2018 ORTP value for offshore wind, especially since the BOEM is currently pursuing multiple offshore wind leases for the New England region, for which an appropriate ORTP is critically important to project financing.

1. **NREL’s Current Data Platform Indicates a Median Overnight Capital Cost of $3,920/kW for Offshore Wind, Well Below the Current Assumption.**

As set forth in Friday’s letter, the National Renewable Energy Laboratory (NREL) is the U.S. Department of Energy’s primary national laboratory for the study and advancement of renewable energy and its principal source of expertise in such matters, including both onshore and offshore wind energy. As part of its **Energy Data for Decision Makers**, NREL has developed Open Energy Information (“Open EI”), a public data platform maintained in conjunction with the DOE that “catalyzes the world’s energy information and links data together in new ways” that is specifically intended to “expand decision-making capabilities.” According to the currently posted assessment in the Transparent Cost Database on Open IE, offshore wind overnight capital cost has a 2012 median value of $3,050/kW and a 2018 median value $2,820/kw, which declines thereafter, as set forth in the NREL chart below, a copy of which is attached as **Appendix A.** Notably, such values are considerably less than the study’s current assumptions of overnight costs, indicating the highly conservative nature of the current analysis.
II. The Bureau of Offshore Energy Management Study, Based on the Actual Costs of 32 Existing Offshore Wind Farms Also Confirms Lower Capital Costs.

The report entitled “Offshore Wind Energy Installation and Decommissioning Cost Estimation in the U.S. Outer Continental Shelf” of the United States Bureau of Ocean Energy Management (“BOEM”, formerly MMS) of the Department of the Interior, the federal agency with primary responsibility for the development, leasing and oversight of wind energy resources on the Outer Continental Shelf of the United States, was based upon extensive analysis of multiple data sets showing the actual capital costs of 32 offshore projects that were either in operation or under construction, including the 4C Offshore commercial database and the Garrad Hassan industry report. The BOEM report concludes that the average capital cost for offshore projects was $3.6 million/MW, with the BOEM report estimating that future projects will be in the range of $4.3 million/MW, a value which it notes is similar to a comparable Ernst & Young study done in 2009:

The average value for all wind farms in the sample was $3.6 million/MW. This estimate is lower than a recent estimate by Ernst and Young (2009) which estimated CAPEX as £3.2 million/MW(approximately $4.8 million/MW at 2009 exchange rates). However, our estimate of $3.6 million/MW is for all wind farms,
while the Ernst and Young estimate is for wind farms to be built in the near future. Including only wind farms to be built after 2010, our CAPEX estimate is $4.3 million/MW, similar to the Ernst and Young estimate.

The average CAPEX of the reference class is slightly larger than the total sample, while the standard deviation is about half that of the total sample. The reference class is more homogenous than the total sample and is expected to have a smaller variance. The reference class is expected to have more consistent patterns of development and to be reflective of future U.S. development.”

follows http://www.bsee.gov/uploadedFiles/BSEE/Research_and_Training/Technology_Assessment_and_Research/6488aa.pdf. (Id., at 134.) As noted below, the BOEM conclusion is based upon a wealth of public data on the actual capital costs of 32 projects:

Table 8.5. Comparison of Normalized Capital Costs by Source (Million $/MW)

<table>
<thead>
<tr>
<th>Wind Farm</th>
<th>Authors</th>
<th>4C*</th>
<th>GR*</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alpha Ventur</td>
<td>6.1</td>
<td>6.1</td>
<td>6.6</td>
<td>6.2</td>
</tr>
<tr>
<td>Arklow**</td>
<td>2.9</td>
<td>2.9</td>
<td>3.1</td>
<td>2.9</td>
</tr>
<tr>
<td>Bard I</td>
<td>4.9</td>
<td>4.9</td>
<td>5.2</td>
<td>4.9</td>
</tr>
<tr>
<td>Barrow**</td>
<td>2.4</td>
<td>2.7</td>
<td>2.7</td>
<td>3.9</td>
</tr>
<tr>
<td>Beatrice</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
</tr>
<tr>
<td>Belwind**</td>
<td>5.2</td>
<td>5.2</td>
<td>5.2</td>
<td>5.9</td>
</tr>
<tr>
<td>Blyth</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
<td>2.1</td>
</tr>
<tr>
<td>Burbo Bank**</td>
<td>3.1</td>
<td>3.1</td>
<td>3.1</td>
<td>3.1</td>
</tr>
<tr>
<td>Global Tech I</td>
<td>4.1</td>
<td>4.1</td>
<td>4.1</td>
<td>4.1</td>
</tr>
<tr>
<td>Greater Gabbard**</td>
<td>3.9</td>
<td>4.2</td>
<td>4.2</td>
<td>3.9</td>
</tr>
<tr>
<td>Gunfleet Sands**</td>
<td>4.4</td>
<td>4.8</td>
<td>4.8</td>
<td>4.9</td>
</tr>
<tr>
<td>Horns Rev</td>
<td>2.9</td>
<td>2.9</td>
<td>2.9</td>
<td>2.9</td>
</tr>
<tr>
<td>Horns Rev II**</td>
<td>3.7</td>
<td>3.7</td>
<td>3.7</td>
<td>3.7</td>
</tr>
<tr>
<td>Kentish Flats**</td>
<td>2.1</td>
<td>2.1</td>
<td>2.1</td>
<td>2.1</td>
</tr>
<tr>
<td>Lilgrund</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
</tr>
<tr>
<td>Lines**</td>
<td>4.1</td>
<td>4.1</td>
<td>4.1</td>
<td>4.1</td>
</tr>
<tr>
<td>London Array**</td>
<td>4.8</td>
<td>4.8</td>
<td>4.8</td>
<td>4.8</td>
</tr>
<tr>
<td>Lynn/Inner Downing**</td>
<td>2.6</td>
<td>2.6</td>
<td>2.6</td>
<td>2.6</td>
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<tr>
<td>Middlegrunden</td>
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<td>4.8</td>
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<tr>
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<td>3.5</td>
<td>3.5</td>
<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Robin Kige**</td>
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<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
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<td>2.7</td>
<td>2.7</td>
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</tr>
<tr>
<td>Samso</td>
<td>2.5</td>
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<td>2.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Scoby Sands</td>
<td>2.2</td>
<td>2.2</td>
<td>2.2</td>
<td>2.2</td>
</tr>
<tr>
<td>Skeringham Shool**</td>
<td>5.2</td>
<td>5.2</td>
<td>5.2</td>
<td>5.2</td>
</tr>
<tr>
<td>Thanet**</td>
<td>4.1</td>
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<td>4.1</td>
<td>4.1</td>
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<tr>
<td>Thornton Bank</td>
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<td>7.3</td>
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<td>2.4</td>
<td>2.4</td>
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</tr>
<tr>
<td>Walney**</td>
<td>4.5</td>
<td>4.5</td>
<td>4.5</td>
<td>4.5</td>
</tr>
<tr>
<td>Ytre Stengrub**</td>
<td>3.3</td>
<td>3.3</td>
<td>3.3</td>
<td>3.3</td>
</tr>
</tbody>
</table>

Average (SD) - All

| 5.7 (1.3) | 3.4 (1.3) | 3.5 (1.7) | 3.6 (1.5) |

Average (SD) - Reference Class**

| 3.7 (0.9) | 3.6 (1.2) | 3.9 (1.2) | 3.7 (0.9) |

Note: *4C = 4Coffshore (2010); GR = Gerrard Hassan (2009);
** Elements in the reference class. Reference class projects are built after 2005 using monopile foundations and capacity greater than 100MW.
The BOEM report further breaks down the capital cost data by year of operation, as shown in Table 8.6 (Id. at 136):

<table>
<thead>
<tr>
<th>Year online</th>
<th>CAPEX (million $/MW)</th>
<th>Number in dataset</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000-2004</td>
<td>2.4</td>
<td>8</td>
</tr>
<tr>
<td>2005-2007</td>
<td>3.2</td>
<td>7</td>
</tr>
<tr>
<td>2008-2010</td>
<td>4.2</td>
<td>9</td>
</tr>
<tr>
<td>2011+</td>
<td>4.3</td>
<td>9</td>
</tr>
</tbody>
</table>

The BOEM report further presents the data by installed capacity increments (Id.):

<table>
<thead>
<tr>
<th>Project type</th>
<th>Capacity (MW)</th>
<th>CAPEX (million $/MW)</th>
<th>Number in dataset</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demonstration</td>
<td>&lt; 20</td>
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<td>3</td>
</tr>
<tr>
<td>Pre-Commercial</td>
<td>20 - 100</td>
<td>5.2</td>
<td>11</td>
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<tr>
<td>Small Commercial</td>
<td>100 - 250</td>
<td>3.2</td>
<td>11</td>
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<tr>
<td>Full Commercial</td>
<td>250 - 750</td>
<td>4.6</td>
<td>8</td>
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<tr>
<td>Large Commercial</td>
<td>&gt; 750</td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

Thus, there is ample public data supporting the capital costs of offshore wind that is based upon actual projects and the analysis of public agencies, and that is as thorough and reliable as the data available for other technologies.

III. Public Data Also Confirms the Operating Cost Assumptions.

The most recent data from several governmental sources, based upon actual experience and agency analysis, also confirms the assumptions of the study as to operating costs, as valid, if not highly conservative. Indeed, the July 2013 edition of *Windpower Monthly* reported the following figures released by U.S., U.K. and Danish authorities, all of which indicate operating costs less than those now assumed, with the Danish agency further stating the expectation of further reductions going forward:

Attention tends to focus on the servicing and spare parts element, which includes both scheduled and unscheduled maintenance, and typically accounts for 25-40% of O&M costs - that is 5-8% of electricity generation costs in the case of onshore wind. O&M costs, according to a recent report from the US Energy Information Administration (EIA), amount to around $40/kW/year for onshore wind and $74/kW/year for offshore wind. The UK's Department of Energy and Climate Change quotes slightly lower figures at $30/kW/year and $57/kW/year, respectively. The Danish Energy Agency's (DEA) figures are slightly lower than
September 19, 13
Page 5

those of US DoE and also suggest these costs will fall by around 30% - both onshore and offshore - by 2030. (Emphasis added)

IV. Conclusion.

While offshore wind may be new to ISO-NE, there is a wealth of clear, public and objective data on all the factors that would be relevant to establishing an ORTP for the 2018 market entry of offshore wind projects, and which would remedy the anomalous treatment relative to onshore wind that became readily apparent only at last week's presentation. As we set forth in last Friday's letter, the prevailing view of objective sources conservatively indicates a 2018 CF of 45% or higher for offshore wind projects and, as set forth above, there is a wealth of objective data on costs that supports the current ORTP study assumptions for offshore wind and, indeed, which shows those assumptions to be conservative in nature. Since the U.S. BOEM is currently pursuing the leasing of wind energy multiple sites off the New England coast and, as set forth above, there is ample public data on all relevant factors, it is critically important to the financing of such projects that an appropriate ORTP be established in accordance with the best available data. We would again welcome the opportunity to meet and discuss the matter further.

Sincerely,

Dennis J. Duffy, Vice President

1 http://www.nrel.gov/analysis/energydata.html
2 http://en.openei.org/apps/TCDB/
3 http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs
September 27, 2013

Mr. David Naughton
ISO New England
Holyoke, Ma

Re: Further Analysis of the 2018 Assumed Offshore Wind Factors

Dear Mr. Naughton,

As we discussed Monday, (i) our letter of September 13 pointed out that the most recently revised Technology Screening Analysis utilized in the ISO-NE ORTP 2013 Study assumed 2018 capacity factor for offshore wind resources that is not in accord with the prevailing view of objective public sources, which would conservatively support a 2018 offshore wind capacity factor for New England of 45%, and (ii) our letter of September 19 provided additional capital cost data that supports cost assumptions at levels well below those presumed in the latest version of the ISO’s Screening Analysis. As requested, we now supplement such information with further explanation of the underlying cost data, as well as additional third party “bottom up” analysis that validates the above-mentioned actual cost data.


As we discussed in our last letter, the BOEM report entitled “Offshore Wind Energy Installation and Decommissioning Cost Estimation in the U.S. Outer Continental Shelf” was based upon extensive analysis of multiple data sets showing the capital costs of actual projects and concludes that the average capital cost for offshore projects was $3.6 million/MW, and the estimated capital cost for future projects will be in the range of $4.3 million/MW, and that the average cost for large-scale projects would be $4.6 million/MW. As BOEM explained in such report, it compiled actual capital cost information from trade journals, company websites, and academic and governmental reports, which it then compared to the leading available commercial databases. BOEM then went on to exclude from the data set any projects where there was not reliable cost information, early-stage projects built before 2000, and Asian projects, resulting in a sample set of 34 actual projects, as well as a “reference case” of 18 post-2005 projects most reflective of future expectations (“The reference case is expected to have more consistent patterns of development and to be reflective of future U.S. development.” Id. at 134):

Capital expenditures were collected from trade journals, company websites, and academic and government reports. These
values were compared using a commercial database (4COffshore) and an industry report (Garrad Hassan 2009). Only wind farms that are operational and generating power, under construction, or for which all capital contracts are finalized are considered. There are a total of 53 offshore wind farms generating power or under construction as of May 2010 (4C Offshore 2010). In addition, there are at least two wind farms for which contracts have been finalized (Lines and London Array) which gives a total sample of 55 wind farms.

Wind farms were excluded from the analysis if there was no reliable information about their costs, if they were built before 2000, or if they were built in Asia. Projects installed before 2000 were excluded because they are primarily of a demonstration character, used small turbines, were placed in benign waters, and are not representative of projects that are currently in development. Projects installed in Asia were excluded because the Asian market is likely to have different costs than the European market.

Table 8.1 shows the wind farms included in the sample and the reasons for exclusion. Of the 55 wind farms, 21 were excluded, leaving 34 projects in the total sample. In most cases (13 of 21), wind farms were excluded due to missing data; in four cases, wind farms were excluded due to their age, and in two cases Asian wind farms were excluded. Additionally, the Hywind project was excluded because the reported costs were nearly an order of magnitude higher than the average cost, and Avedore Holmes was excluded as it is not truly offshore.

From the 34 wind farms included in the total sample, we created a reference class of wind farms for the purpose of installation cost estimation. In this case, we excluded all wind farms built before 2005 and all wind farms built on non-monopile foundations. The reference class included 18 wind farms. We analyze the capital expenditures of both the total sample and the reference cases.

follows: http://www.bsee.gov/uploadedFiles/BSEE/Research_and_Training/Technology_Assessment_and_Research/648aa.pdf. (Id., at 134, emphasis added)

BOEM goes on to explain that all project costs were “normalized” to adjust for inflation and currency differentials so as to allow for effective $/MW comparisons. Id. at 134. Notably, BOEM further validated the results of its analyses by comparison to the leading independent cost studies, including the databases of 4COffshore and Garrad Hassan, the industry’s foremost international consultant firm, as well as the independent cost report of Ernst & Young, and such comparison showed BOEM’s cost conclusions to be comparable to all such sources. Id. at 128, 134. Thus, the BOEM Report is well-researched and documented governmental analysis of
II. BOEM Validated its Report by Reference to the Ernst & Young “Bottom-Up” Analysis That Shows Consistent Results.

As one means of validating the actual capital costs analysis discussed above, the BOEM Report (id. at 128, 134) referenced the Ernst & Young report entitled “Cost and Financial Support of Offshore Wind, A Report for the Department of Energy and Climate Change,” which conducted a “bottom-up” cost analysis based upon components of capital costs, utilizing publically available data, proprietary Ernst & Young information, and information obtained from governmental agencies, which indicated capital cost results comparable to those of the BOEM’s analysis based on actual costs. The Ernst & Young report states its purpose as “an assessment of the current capital and operating costs for offshore wind projects in the UK and the historical evolution of the key drivers of these costs,” as well as of “the likely evolution of such costs” for the purpose of governmental public policy analysis.

Whereas the BOEM analysis estimated capital costs of $4,600/kw for future large utility-scale projects, Ernst & Young’s analysis of capital cost components indicated a combined total capital cost of approximately $4,800/kw (i.e., £3.2/mw) and, further, broke out the major capital cost components on both a price and percentage basis, as follows:

“Current estimated capital costs have been derived from the megawatt-weighted average of project capital costs for projects at or near financial close in January 2009 of £3.2m per MW. Further analysis shows that the Material Costs to capital costs for projects at or near financial close in January 2009 include (see):

- Wind turbine generators (WTG), which make up around 47% at £1.5m per MW.
- Foundations, which make up around 22% at £0.7m per MW.
- Electrical infrastructure, which makes up around 19% at £0.6m per MW.
- Planning and development costs, which make up the remaining 12% at £0.4m per MW.”

Id. at 15. The BOEM thus concluded that the two study methods yielded comparable results: “Including only wind farms to be built after 2010, our CAPEX estimate is $4.3 million/MW, similar to the Ernst and Young estimate.” BOEM Report at 134.
Thus, the U.S. government’s lead agency for offshore renewable energy, the BOEM, has incorporated the “bottom-up” analysis of the Ernst & Young report conducted for U.K. governmental agencies to confirm and validate the BOEM’s conclusions based upon an extensive database of actual cost experience. Moreover, the “similar” results of both of such study methods demonstrate the conservative nature of higher capital cost assumptions currently reflected in the latest ISO ORTP analysis. As indicated, there is ample public data supporting the capital costs of offshore wind, based upon both actual project cost experience and “bottom up” analysis, that is as thorough and reliable as the data available for other technologies.

III. Conclusion.

As we set forth above and in our prior letters, the prevailing view of objective sources conservatively indicates a 2018 CF of 45% or higher for New England offshore wind projects, and objective cost data (on both an “actual-cost” and “bottom-up” basis) shows the current capital cost assumptions for offshore wind in the ORTP study to be conservative in nature. Since the U.S. BOEM is currently pursuing the leasing of wind energy multiple sites off the New England coast, it is critically important that the values input into the ISO’s “capital budgeting model” reflect the best available data, so that the output of the model yields an ORTP that fairly reflects economic reality, and that places offshore wind on a level playing field with other technologies. We would again welcome the opportunity to provide any further information that would be helpful.

Sincerely,

Dennis J. Duffy, Vice President
The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1  Offer Review Trigger Prices.
For each new technology resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the Ninth/Eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017) shall be as follows:

<table>
<thead>
<tr>
<th>Generation Resources</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology Type</td>
<td></td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>$13.42416</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.754866</td>
</tr>
<tr>
<td>Off-Shore Wind</td>
<td>$0.000</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$9.870.000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demand Resources - Commercial and Industrial</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology Type</td>
<td></td>
</tr>
<tr>
<td>Dispatchable Load Management</td>
<td>$1.1455</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>
Energy Management, Inc. Amendment

### Demand Resources – Residential

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable Load Management</td>
<td>$7.094</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>$10.00</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$11.00</td>
</tr>
<tr>
<td>Biomass</td>
<td>$24.00</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$14.00</td>
</tr>
<tr>
<td>Real-Time Demand Response</td>
<td>$1.00</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.00</td>
</tr>
<tr>
<td>All Other Resource Types</td>
<td>Forward Capacity Auction Starting Price</td>
</tr>
</tbody>
</table>

Where a new resource is composed of assets having different technology resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology resource type of the External Resource.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be $0.00/kW-month.

### III.A.21.1 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology resource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs,
assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure programs’ life.

(d) For new Real-Time Demand Response Resources other than energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those using energy efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than energy efficiency Demand Resources) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs. The Internal Market Monitor is based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is
calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

(c) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Steam Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Wind Turbines</td>
<td>Bloomberg Wind Turbine Price Index</td>
</tr>
<tr>
<td>Other Equipment</td>
<td>BLS-PPI &quot;General Purpose Machinery and Equipment&quot;</td>
</tr>
</tbody>
</table>
| Construction Labor      | Composite index developed from RS Means labor categoriesBLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:  
                         | - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts  
                         | - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine |
| Other Labor             | Composite index developed from BLS job classificationsBLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:  
                         | - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts  
                         | - On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine |
| Materials               | BLS-PPI "Materials and Components for Construction"                  |
| Electric Interconnection| BLS - PPI "Electric Power Transmission, Control, and Distribution"BLS-PPI "Electric Power Distribution" |
| Gas Interconnection     | BLS - PPI "Natural Gas Distribution; Delivered to ultimate consumers for the account of others (transportation only)"BLS-PPI "Oil and Gas Field Machinery and Equipment" |
| Fuel Inventories        | Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)” |

(21) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor, Administrative and</td>
<td>BLS “Quarterly Census of Employment and Wages” 2211 Power</td>
</tr>
</tbody>
</table>
For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent twelve month period available at the time of making the adjustment divided by the average of the most recent twelve month period available at the time of establishing values included in the capital budgeting model used to establish the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by a multiplier calculated by using inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update that corresponds through to the end first year of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the twelve months following the time of the update, as published by NYMEX the CME Group divided by the Henry Hub natural gas price used in the capital budgeting model.

Renewable Energy Credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest that corresponds to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

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

III.A.21.2 New Resource Offer Floor Prices.
For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant technology resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation
and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Real-Time Demand Response Resource, the resource’s costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider and end-use customers to acquire the Real-Time Demand Response Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Real-Time Demand Response Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource’s qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project’s pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource’s New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be equal to the requested offer price.
Energy Management, Inc. Amendment

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource’s qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.


For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource’s long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.
(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

   (i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

   (ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.
The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1  Offer Review Trigger Prices.
For each new technology resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price.
Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ninth eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 20182017) shall be as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation Resources</td>
<td></td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>$13.42165 $14.56 $15.04</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.75466610.189.69</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$9,870.000</td>
</tr>
<tr>
<td>Demand Resources – Commercial and Industrial</td>
<td></td>
</tr>
<tr>
<td>Dispatchable Load Management</td>
<td>$1.1455</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>based on generation technology type</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.000</td>
</tr>
<tr>
<td>Demand Resources – Residential</td>
<td></td>
</tr>
</tbody>
</table>
Where a new resource is composed of assets having different technology resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology resource type of the External Resource.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be $0.00/kW-month.

### III.A.21.1.2 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology resource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project.
The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure programs’ life.

(d) For new Real-Time Demand Response Resources other than energy efficiency Demand Resources, the methodology used to develop the Offer Review Trigger Price is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those using energy efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than energy efficiency Demand Resources) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs, based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger
Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Steam Turbines</td>
<td>BLS-PPI &quot;Turbines and Turbine Generator Sets&quot;</td>
</tr>
<tr>
<td>Wind Turbines</td>
<td>Bloomberg Wind Turbine Price Index</td>
</tr>
<tr>
<td>Other Equipment</td>
<td>BLS-PPI &quot;General Purpose Machinery and Equipment&quot;</td>
</tr>
<tr>
<td>Construction Labor</td>
<td>Composite index developed from RS Means labor categoriesBLS &quot;Quarterly Census of Employment and Wages&quot; 2371 Utility System Construction Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Other Labor</td>
<td>Composite index developed from BLS job classificationsBLS &quot;Quarterly Census of Employment and Wages&quot; 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
<tr>
<td></td>
<td>- On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine</td>
</tr>
<tr>
<td>Materials</td>
<td>BLS-PPI &quot;Materials and Components for Construction&quot;</td>
</tr>
<tr>
<td>Electric Interconnection</td>
<td>BLS - PPI &quot;Electric Power Transmission, Control, and Distribution&quot; BLS-PPI &quot;Electric Power Distribution&quot;</td>
</tr>
<tr>
<td>Gas Interconnection</td>
<td>BLS - PPI &quot;Natural Gas Distribution&quot; BLS-PPI &quot;Oil and Gas Field Machinery and Equipment&quot;</td>
</tr>
<tr>
<td>Fuel Inventories</td>
<td>Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”</td>
</tr>
</tbody>
</table>

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor, Administrative and General</td>
<td>BLS &quot;Quarterly Census of Employment and Wages&quot; 2211 Power Generation and Supply Average Annual Pay:</td>
</tr>
<tr>
<td></td>
<td>- Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts</td>
</tr>
</tbody>
</table>
On-Shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine

<table>
<thead>
<tr>
<th>Materials and Contract Services</th>
<th>BLS-PPI &quot;Materials and Components for Construction&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site Leasing Costs</td>
<td>Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”</td>
</tr>
</tbody>
</table>

(32) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent twelve month period available at the time of making the adjustment divided by the average of the most recent twelve month period available at the time of establishing values included in the capital budgeting model used to establish the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(43) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by a multiplier calculated by using inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices from the time of the update that corresponds through to the end first year of the Capacity Commitment Period associated with the relevant FCA, and the Massachusetts Hub On-Peak electricity prices and the Algonquin City Gates natural gas prices for the twelve months following the time of the update, as published by NYMEX the CME Group divided by the Henry Hub natural gas price used in the capital budgeting model.

(54) Renewable Energy Credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest that corresponds to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(65) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(76) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

### III.A.21.2 New Resource Offer Floor Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.
(a) For a new capacity resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant technology resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.
For a new Real-Time Demand Response Resource, the resource’s costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider and end-use customers to acquire the Real-Time Demand Response Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Real-Time Demand Response Resource.

For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

Sufficient documentation and information must be included in the resource’s qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project’s pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource’s New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be equal to the requested offer price.

If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s
New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource’s qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.


For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource’s long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:
(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.
December 5, 2013

Gordon van Welie, CEO
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Setting an Offer Review Trigger Price for Offshore Wind for 2018-2020

Dear Mr. Van Welie,

I would like to thank you and the entire staff at ISO New England for your dedicated work in expertly maintaining the region’s electric grid. Though complicated and complex, the ISO continuously ensures that our consumers are provided reliable electric service in the Commonwealth and New England at large.

It has come to my attention that the NEPOOL Markets Committee voted on November 13th to establish an Offer Review Trigger Price ("ORTP") for offshore wind projects. I am writing to urge the ISO to establish an ORTP in compliance with the NEPOOL Markets Committee vote on that day. Without those changes, I understand that it may be significantly more difficult for offshore wind projects to clear in a Forward Capacity Market ("FCM"). Investor confidence is very important for any new energy development, and uncertainty regarding capacity resource status is particularly important here, as offshore wind developers will need to expend tens of millions of dollars well in advance of eligibility for any FCM auction. Additionally, I fear that the failure of certain renewable energy developments to qualify as a capacity resource in the Forward Capacity Market may lead Massachusetts ratepayers to pay for redundant generation. I urge you to establish an ORTP of $0/kW-month for offshore wind facilities.

Thank you for your consideration on this matter of great importance to the Commonwealth.

Very Best Regards,

John D. Keenan, State Representative
7th Essex District, Salem
House Chair, Joint Committee of Telecommunications, Utilities and Energy
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot, Paul Belval and Sebastian Lombardi, NEPOOL Counsel

DATE: November 27, 2013

RE: ISO New England’s FCM Performance Incentives Proposal

At its December 6, 2013 meeting, the Participants Committee will be asked to consider a number of revisions to the Forward Capacity Market (FCM) rules proposed by ISO New England to implement its FCM Performance Incentives Proposal and related mitigation design (collectively, the PI Proposal). A copy of all of such Tariff revisions are included with this memorandum, along with background materials.

One set of proposed FCM changes to the Market Rules have been considered and voted on by the Markets Committee, and another set of corresponding changes to ISO-NE’s Financial Assurance Policy were recently considered by the Budget & Finance Subcommittee. The Market Rule changes require a 60% Vote to pass while the Financial Assurance Policy changes require a 66.67% Vote. Accordingly, the Participants Committee will be asked to consider and take action on the PI Proposal in two separate motions. The first motion will ask the Participants Committee to support ISO-proposed revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2 (Definitions). The second motion will ask the Participants Committee to support related changes to the Financial Assurance Policy proposed by the ISO to revise financial assurance requirements to account for the market changes to implement the PI Proposal. This memorandum provides further detail on each set of changes and also discusses potential Participant-sponsored amendments to those changes of which we have been advised.

If any Participant wishes to offer amendment(s) to ISO’s proposed set of changes not already included with this memorandum, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com) as soon as possible so that they can be circulated, reviewed and considered ahead of the meeting. Consistent with past practice, Participants are reminded that procedural objections will not be raised by NEPOOL or the ISO in any subsequent FERC proceeding should an amendment that was already considered, but not supported previously at the November 13-14, 2013 Markets Committee meeting, be advocated to the FERC notwithstanding that it was not presented for a vote by the Participants Committee.

Motion #1. ISO’s Proposed Market Rule Changes to Implement FCM PI

ISO-NE proposes to modify the current FCM penalty structure with the aim of creating stronger incentives for resource performance in the Forward Capacity Market (FCM PI). The ISO believes that FCM PI will provide a long-term solution to enhance resource performance and availability, especially during times of high system stress, which will help to address reliability risks associated with region’s growing reliance on natural gas-fired generation. As proposed by the ISO, FCM PI would be implemented beginning with the Capacity Commitment Period associated with the ninth Forward Capacity Auction (FCA9) (beginning June 1, 2018).
FCM PI as proposed by ISO-NE would replace the existing Shortage Event penalty structure with a new ‘performance incentive’ mechanism, resulting in capacity payments to resources that are the combination of two components: (1) a base capacity payment and (2) a performance payment or charge. The base payment would be determined by the results of a Forward Capacity Auction, while the performance payment or charge would depend on a resource’s performance during scarcity conditions (i.e., 10- or 30-minute reserve deficiencies). Capacity suppliers that perform better than a benchmark level would receive performance payments and those performing below that benchmark level would be assessed a charge that would reduce the net capacity payments to the resource. The performance payments and charges will be established such that performance charges to resources that under-perform would provide the revenues to compensate the resources that over-perform during the scarcity condition.

During stakeholder discussions, the ISO agreed to two changes to an earlier FCM PI proposal. First, the ISO’s final proposal includes so-called “stop loss” provisions to cap aggregate performance charges at annual limits. Second, the Performance Payment Rate for performance better than the associated benchmark would be phased in over time rather than be set at the initially proposed rate of $5,455 per MWh. The phase in would be as follows: $2,000 per MWh in FCAs 9, 10 and 11 (Capacity Commitment Periods 2018-19 to 2020-21); $3,500 per MWh in FCAs 12, 13 and 14 (Capacity Commitment Periods 2021-22 to 2023-24); and $5,455 per MWh thereafter. A copy of the ISO’s proposed Market Rule changes to implement FCM PI are included with this memorandum as Attachment A.

Markets Committee Consideration

The NEPOOL Markets Committee, along with state regulators, have vetted the ISO’s FCM PI proposal over the last year. Those discussions culminated in a series of votes taken at the November 13-14, 2013 Markets Committee meeting. There were thirteen Participant-sponsored amendments proposed to the ISO’s FCM PI, one of which received broad support (see Brookfield Amendment #3 below). The remaining twelve amendments were not supported by the Markets Committee, and the once-amended main motion was overwhelmingly opposed. Similarly, and at the request of the ISO, the Markets Committee failed to recommend Participants Committee support for the unamended FCM PI proposal, with only a hand-full of votes registering support for the ISO’s proposal. A copy of the November 13-14 Notice of Actions of the Markets Committee detailing these votes, including amendments proposed at the Markets Committee, is also included with this memorandum as Attachment B.

Potential Motions to Amend the FCM PI Proposal

As indicated, thirteen motions to amend the ISO’s FCM PI proposal were voted by the Markets Committee at its November 14 meeting. Accordingly, the Participants Committee may be asked to consider any or all of those amendments, as follows: (Further details on these amendments are included with this memorandum as Attachment C)
A. **Brookfield Proposals**

The first Brookfield proposal (Brookfield Amendment #1) would provide an exemption for Intermittent Power Resources from the penalties associated with FCM PI. Based on a show of hands vote, this amendment was not supported by the Markets Committee. See Attachment C-1.

The next Brookfield amendment (Brookfield Amendment #2), would revise Section III.13.7.2.2 (b) to Market Rule 1 to exempt, from FCM PI non-performance penalties, any External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols. This motion to amend failed with a 19.69% Vote in favor at the Markets Committee. See Attachment C-2.

The third proposed amendment (Brookfield Amendment #3) would amend language in Section III.13.7.2.4 such that, if a resource is subject to an ISO-imposed limit, the resource would not be penalized for non-delivery of energy or reserves above that ISO-imposed restriction. As defined by Brookfield, ISO-imposed limits include transmission outages, derates, voltage issues, and largest system contingency protection restrictions. Brookfield Amendment #3 was supported by the Markets Committee with a 71.77% Vote in favor. See Attachment C-3.

B. **NextEra Amendment**

The NextEra amendment would (i) set the Performance Payment Rate at $5,455 per MWh (beginning with FCA9), (ii) provide a limited exemption for transmission-related outages and (iii) change the monthly “stop loss” provisions. NextEra’s proposed package of changes failed to garner sufficient support for a Markets Committee recommendation, with a 12.15% Vote in favor. See Attachment C-4.

C. **MMWEC Proposal**

MMWEC’s packaged amendment would revise Market Rule 1 to exempt the following from the FCM PI provisions: (1) Import Capacity associated with NYPA contracts; (2) Intermittent Power Resources; and (3) resources that are unable to perform or are out-of-service due to a planned outage or loss of transmission. The MMWEC motion to amend failed with a Markets Committee Vote of 49.35% in favor. See Attachment C-5.

D. **NU Proposals**

The first NU amendment (NU Amendment #1) would exempt a resource from FCM PI if that resource’s inability to deliver energy or reserves during a scarcity condition is due to an outage or de-rate of a transmission facility in the New England Control Area. This amendment failed with a 42.06% Vote in favor at the Markets Committee. NU plans to offer similar, but slightly updated amendment language for this proposal at the December 6 Participants Committee meeting. See Attachment C-6.
NU Amendment #2 would amend FCM PI to maintain the current FCM performance rules for passive demand resources. This amendment failed by a show of hands vote. See Attachment C-7.

The third NU Amendment (NU Amendment #3) would reinstate current Market Rule provisions in Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource’s Capacity Performance Payment under FCM PI. Like NU Amendment #2, this third amendment also failed based on a show of hands at the Markets Committee. See Attachment C-8.

E. EquiPower Proposal

The EquiPower amendment would permit an existing resource to submit a Static De-List Bid for up to the MW amount that the Market Participant expects may not be physically available due to reductions in ratings as measured by EFORd times summer Qualified Capacity at 90 degrees. This proposed mechanism is similar to the current construct used for “Ambient Air De-List Bids.” Based on a show hands, the Markets Committee failed to recommend support for the EquiPower amendment. See Attachment C-9.

F. GDF SUEZ Proposals

The Markets Committee also considered and failed to support two separate, but related amendments offered by GDF SUEZ to revise the Peak Energy Rent (PER) mechanism in the FCM. GDF SUEZ Amendment #1 would eliminate the PER deduction (See Attachment C-10) and GDF SUEZ Amendment #2 would modify the PER deduction to avoid penalizing resources for performing in real-time (See Attachment C-11). Both amendments failed with Markets Committee Votes of 45.12% and 45.16% in favor, respectively.

G. Dominion Alternative Proposal

Dominion’s alternative proposal would replace ISO’s FCM PI proposal with an EFORd pay-for-performance approach. In addition, Dominion would maintain the enhanced Shortage Event penalty mechanism that was recently accepted by the FERC (effective as of Nov. 3, 2013). The Dominion alternative failed with a 21.74% Vote in favor at the Markets Committee. See Attachment C-12.

H. NRG Alternative Proposal

At the Markets Committee, NRG offered an alternative proposal that would strike out all of ISO’s proposed Tariff provisions to implement FCM PI and instead revise the current Market Rules. NRG’s alternative included changes to improve energy market pricing, measure performance using EFORp, eliminate the PER deduction, permit offer prices for existing resources (delist bids) based on ‘long-run average costs’ rather than ‘net risk-adjusted going-forward costs’ and establish the Dynamic De-List Bid threshold at 80% of the Offer Review Trigger Price of a combustion turbine. This proposed alternative failed with a Markets Committee Vote of 31.65% in favor.
Based on additional feedback received from stakeholders, NRG plans to ask the Participants Committee to vote on the same substance that was considered by the Markets Committee, but in three separate votes (or three distinct amendments). These amendments are described in NRG’s November 27 memo to the Participants Committee, which is included with this memorandum as Attachment C-13.

The following form of resolution may be used as main motion #1 for Participants Committee action on FCM PI:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A to Market Rule 1 and Section 1.2.2 (Definitions) to implement the FCM Performance Incentives Proposal and mitigation design, as proposed by ISO and as 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 and Vice-Chair of the Markets Committee.

Motion #2. ISO’s FCM PI Financial Assurance Changes

The ISO-proposed modifications to the ISO-NE Financial Assurance Policy (FA Changes) would expand financial assurance requirements to include the obligations for FCM PI in each Market Participant’s calculation of its financial assurance obligations. A copy of those proposed FA Changes are included with this memorandum as Attachment D.

The Budget and Finance Subcommittee discussed the FA Changes on its November 18 and November 25 teleconferences. With one exception, none of the Subcommittee members attending the November 25 teleconference expressed any concerns that were specific to the Financial Assurance Policy, although several Subcommittee members reserved their rights to object to the FA Changes as part of the larger PI Proposal. Also, one Subcommittee member from the AR Sector expressed concerns with how the FA Changes might impact state-sponsored energy efficiency programs and indicated to the Subcommittee that he may offer an amendment to those changes for Participants Committee consideration at its December 6 meeting.

The following form of resolution may be used for Participants Committee action on the FA Changes related to the PI Proposal:

RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO-NE Financial Assurance Policy to establish financial assurance requirements under the FCM Performance Incentives Proposal, as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with [any changes agreed to at this meeting and] such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve.
Agenda Item 10:
Proposed Order of Motions for FCM PI Item
December 6, 2013 NPC Meeting

A. Main Motion #1 on ISO’s FCM PI Proposal (See Attachment A for Tariff revisions)

B. With Main Motion #1 on the table, then consideration of any Motions to Amend the FCM PI Proposal

1. Brookfield Amendment #1 (See Attachment C-1): Provides an exemption for Intermittent Power Resources from the penalties associated with FCM PI. Based on a show of hands vote, this amendment was not supported by the Markets Committee.

2. MMWEC Amendment #1 (See Attachment C-5): Adds the following language, “Intermittent Power Resources shall be exempt from provisions set forth in this Section III.13.7.2.” Under this proposed exemption, Intermittent Resources would not be subject to the PI penalty, but unlike Brookfield Amendment #1 would also not be eligible to receive a performance payment.

3. Brookfield Amendment #2 (See Attachment C-2): Revises Section III.13.7.2.2 (b) to Market Rule 1 to exempt, from FCM PI non-performance penalties, any External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols. This motion to amend failed with a 19.69% Vote in favor at the Markets Committee.

4. NU Amendment #1 (See Attachment C-6): Would exempt a resource from FCM PI if that resource’s inability to deliver energy or reserves during a scarcity condition is due to an outage or de-rate of a transmission facility in the New England Control Area. This amendment failed with a 42.06% Vote in favor at the Markets Committee. This amendment is similar to one offered at the MC, but with slightly updated amendment language for NPC consideration.

5. Brookfield Amendment #3 (See Attachment C-3): Amends language in Section III.13.7.2.4 such that, if a resource is subject to an ISO-imposed limit, the resource would not be penalized for non-delivery of energy or reserves above that ISO-imposed restriction. Brookfield Amendment #3 was supported by the Markets Committee with a 71.77% Vote in favor.

6. MMWEC Amendment #2 (See Attachment C-5): Revises Market Rule 1 to exempt the following from the FCM PI provisions: (1) Import Capacity associated with NYPA contracts and (2) resources that are unable to perform or are out-of-service due to a planned outage or loss of transmission. Also revises ISO-proposed Section III.13.7.2.5 as follows: “The ISO shall review the Performance Payment Rate in the stakeholder process as needed annually and shall filed with the Commission a new Capacity Performance Rate if and as appropriate.”
7. **NextEra Amendment** *(See Attachment C-4)*: (i) sets the Performance Payment Rate at $5,455 per MWh (beginning with FCA9), (ii) provides a limited exemption for transmission-related outages and (iii) makes a change to the monthly “stop loss” provisions. NextEra’s proposed package of changes failed to garner sufficient support for a Markets Committee recommendation, with a 12.15% Vote in favor.

8. **EquiPower Amendment** *(See Attachment C-9)*: Would permit an existing resource to submit a Static De-List Bid for up to the MW amount that the Market Participant expects may not be physically available due to reductions in ratings as measured by EFORd times summer Qualified Capacity at 90 degrees. This proposed mechanism is similar to the current construct used for “Ambient Air De-List Bids.” Based on a show hands, the Markets Committee failed to recommend support for the EquiPower amendment.

9. **NU Amendment #2** *(See Attachment C-7)*: Amend FCM PI to maintain the current FCM performance rules for passive demand resources. This amendment failed by a show of hands vote at MC.

10. **NU Amendment #3** *(See Attachment C-8)*: Inserts current Market Rule provisions in the ISO-proposed Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource’s Capacity Performance Payment under FCM PI. Failed based on a show of hands at the Markets Committee.

11. **PSEG Amendment** *(See Attachment C-14)*: Revise Section III.13.2.4 (Forward Capacity Auction Starting Price) to set FCA 9 starting price at $22/kW-month. *This amendment was not previously considered at the MC.*

12. **Dominion Alternative Proposal** *(See Attachment C-12)*: Replaces ISO’s FCM PI proposal with an EFORd pay-for-performance approach. In addition, Dominion would maintain the enhanced Shortage Event penalty mechanism that was recently accepted by the FERC (effective as of Nov. 3, 2013). The Dominion alternative failed with a 21.74% Vote in favor at the Markets Committee.

13. **NRG Alternative #1** *(See Attachment C-13)*: Strikes out all of ISO’s proposed Tariff provisions to implement FCM PI and revises the current Market Rules instead. NRG Alternative #1 increased the Reserve Constraint Penalty Factors (RCPF) for System TMOR from $500 to $1,000, and for System TMNSR from $850 to $1,500 and replaces the current ‘Shortage Event’ mechanism with a mechanism to measure performance using EFORp.

14. **GDF SUEZ Amendment #1** *(See Attachment C-10)*: Proposes to eliminate the PER deduction in the FCM. Failed with Markets Committee Vote of 45.12% in favor.

15. **GDF SUEZ Amendment #2** *(See Attachment C-11)*: Modifies the PER deduction to avoid penalizing resources for performing in real-time. Failed at MC with 45.16% in favor.
16. **NRG Alternative #3 (See Attachment C-13):** Strikes out all of ISO’s proposed Tariff provisions and revises the current Market Rules to (i) permit offer prices for existing resources (delist bids) based on ‘long-run average costs’ rather than ‘net risk-adjusted going-forward costs’, (ii) establish the Dynamic De-List Bid threshold at 80% of the Offer Review Trigger Price of a combustion turbine, and (iii) enable Existing Resources with IMM-approved offers above the Dynamic-List Bid threshold to participate in the auction at process below the IMM-approved price.

C. **[If Applicable] Amended Main Motion #1**

D. **Unamended Main Motion #1 (or unamended ISO-NE Proposal)**

E. **Main Motion #2 on ISO’s FCM PI Financial Assurance Changes (See Attachment D)**

F. **[If Applicable] Consideration of any Motions to Amend Main Motion #2**
Agenda Item 10: Proposed Order of Motions for FCM PI Item
December 6, 2013 NPC Meeting

A. Main Motion #1 on ISO’s FCM PI Proposal (See Attachment A for Tariff revisions)

B. With Main Motion #1 on the table, then consideration of any Motions to Amend the FCM PI Proposal

1. Brookfield Amendment #1 (See Attachment C-1): Provides an exemption for Intermittent Power Resources from the penalties associated with FCM PI. Based on a show of hands vote, this amendment was not supported by the Markets Committee.

2. MMWEC Amendment #1 (See Attachment C-5): Adds the following language, “Intermittent Power Resources shall be exempt from provisions set forth in this Section III.13.7.2.” Under this proposed exemption, Intermittent Resources would not be subject to the PI penalty, but unlike Brookfield Amendment #1 would also not be eligible to receive a performance payment.

3. Brookfield Amendment #2 (See Attachment C-2): Revises Section III.13.7.2.2 (b) to Market Rule 1 to exempt, from FCM PI non-performance penalties, any External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols. This motion to amend failed with a 19.69% Vote in favor at the Markets Committee.

4. NU Amendment #1 (See Attachment C-6): Would exempt a resource from FCM PI if that resource’s inability to deliver energy or reserves during a scarcity condition is due to an outage or de-rate of a transmission facility in the New England Control Area. This amendment failed with a 42.06% Vote in favor at the Markets Committee. This amendment is similar to one offered at the MC, but with slightly updated amendment language for NPC consideration.

5. Brookfield Amendment #3 (See Attachment C-3): Amends language in Section III.13.7.2.4 such that, if a resource is subject to an ISO-imposed limit, the resource would not be penalized for non-delivery of energy or reserves above that ISO-imposed restriction. Brookfield Amendment #3 was supported by the Markets Committee with a 71.77% Vote in favor.

6. MMWEC Amendment #2 (See Attachment C-5): Revises Market Rule 1 to exempt the following from the FCM PI provisions: (1) Import Capacity associated with NYPA contracts and (2) resources that are unable to perform or are out-of-service due to a planned outage or loss of transmission. Also revises ISO-proposed Section III.13.7.2.5 as follows: “The ISO shall review the Performance Payment Rate in the stakeholder process as needed annually and shall filed with the Commission a new Capacity Performance Rate if and as appropriate.”
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9. **NU Amendment #2** *(See Attachment C-7):* Amend FCM PI to maintain the current FCM performance rules for passive demand resources. This amendment failed by a show of hands vote at MC.

10. **NU Amendment #3** *(See Attachment C-8):* Inserts current Market Rule provisions in the ISO-proposed Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource’s Capacity Performance Payment under FCM PI. Failed based on a show of hands at the Markets Committee.

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C. **[If Applicable] Amended Main Motion #1**

D. **Unamended Main Motion #1 (or unamended ISO-NE Proposal)**

E. **Main Motion #2 on ISO’s FCM PI Financial Assurance Changes (See Attachment D)**

F. **[If Applicable] Consideration of any Motions to Amend Main Motion #2**
1.2  Rules of Construction; Definitions

1.2.1.  Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a)  words denoting the singular include the plural and vice versa;
(b)  words denoting a gender include all genders;
(c)  references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
(d)  the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
(e)  a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
(f)  a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
(g)  a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
(h)  a reference to any person (as hereinafter defined) includes such person’s successors and permitted assigns in that designated capacity;
(i)  any reference to “days” shall mean calendar days unless “Business Days” (as hereinafter defined) are expressly specified;
(j)  if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day without, in the case of any such payment, the payment or accrual of any interest or
other late payment or charge, provided such payment is made on such next succeeding Business
Day); (k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import
shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any
particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or
“including” means including without limiting the generality of any description preceding such
term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general
statement, followed by or referable to an enumeration of specific matters, to matters similar to
those specifically mentioned.

I.2.2. Definitions
In this Tariff, the terms listed in this section shall be defined as described below:

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

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response
Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

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

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

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

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

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by
certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of
the New England Control Area during the associated Capacity Commitment Period, as described in
Section III.13.1.2.3.1.4 of Market Rule 1.
Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

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

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

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

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

AGC is automatic generation control.

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

Alternative Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

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

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.
Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

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

Annualized FCA Payment is used to determine a resource’s availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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

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

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO’s website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO’s dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.
Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of “unavailable” for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

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

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

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource’s most recent audit.
Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

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

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

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource’s electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource’s electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Resources associated with the Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource’s electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource’s Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource’s electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource’s electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource’s Measurement and Verification Plan, which shall be reviewed by the ISO to ensure
consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

**Average Monthly PER** is calculated in accordance with Section III.13.7.2.7.1.2(a) of Market Rule 1.

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

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

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

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

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

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

**Blackstart CIP Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station’s costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

**Blackstart CIP O&M Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a
Blackstart Station’s operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

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

**Blackstart O&M Payment** is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource’s operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

**Blackstart Service** is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses “System Restoration and Planning Service” under the predecessor version of Schedule 16.

**Blackstart Service Commitment** is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

**Blackstart Service Minimum Criteria** are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.
**Blackstart Standard Rate Payment** is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

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

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

**Blackstart Station-specific Rate Capital Payment** is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for the day); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a
related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

**Cancellation Fee** is defined in Section III.1.10.2(d).

**Cancelled Start Credit** is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

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

**Capability Year** means a year’s period beginning on June 1 and ending May 31.

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

**Capacity Balancing Ratio** is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on December 31, 2013.

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

**Capacity Carried Forward Due to Rationing** is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.
**Capacity Clearing Price** is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

**Capacity Clearing Price Floor** is described in Section III.13.2.7.

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

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

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

**Capacity Load Obligation** is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant’s Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

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

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

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

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

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on December 31, 2013.

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

Capacity Requirement is described in Section III.13.7.3.1 of Market Rule 1.

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

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

Capacity-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder’s entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.
Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

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

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

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

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

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

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

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.
**Coincident Peak Contribution** is a Market Participant’s share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year’s annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

**Cold Weather Conditions** means any calendar day when that day’s Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day’s total Effective Heating Degree Days are forecast to be greater than or equal to 65.

**Cold Weather Event** means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

**Cold Weather Warning** means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

**Cold Weather Watch** means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

**Commercial Capacity**, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

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

**Common Costs** are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.
Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

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

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

Conditional Qualified New Generating Capacity Resource is defined in Section III.13.1.2.3(f) of Market Rule 1.

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

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

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

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

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

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

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

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

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

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.
Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

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

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

Cost of New Entry (CONE) is the value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

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

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

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

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

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

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.
Current Ratio is, on any date, all of a Market Participant’s or Non-Market Participant Transmission Customer’s current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.
Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

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

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

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

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

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

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

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

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

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

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

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.
**Default Amount** is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

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

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

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

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

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

**Demand Reduction Offer** is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

**Demand Reduction Value** is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

**Demand Resource** is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time
Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

**Demand Resource Commercial Operation Audit** is an audit initiated pursuant to Section III.13.6.1.5.4.4.

**Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO’s most recent next-day forecast.

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

**Demand Resource Operable Capacity Analysis** means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

**Demand Resource Performance Incentives** means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

**Demand Resource Performance Penalties** means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.
**Demand Resource Seasonal Peak Hours** are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

**Demand Response Asset** is the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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

**Demand Response Baseline** is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

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

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

**Demand Response Resource** is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.
Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

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

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

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

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

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

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

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

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

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

**Dispatch Rate** means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.
Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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

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

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

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.
**Dynamic De-List Bid** is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or below the **Dynamic De-List Bid Threshold** prices of $1.00/kW-month or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

**Economic Maximum Limit or Economic Max** is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource’s Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.
**Economic Minimum Limit or Economic Min** is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit’s Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

**EFT** is electronic funds transfer.

**Effective Heating Degree Days** is equal to 68 – (average of max and min Effective Temperature of the day).

**Effective Temperature** is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

**Elective Transmission Upgrade** is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

**Elective Transmission Upgrade Applicant** is defined in Section II.47.5 of the OATT.

**Electric Reliability Organization (ERO)** is defined in 18 C.F.R. § 39.1.
**Electronic Dispatch Capability** is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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

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

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

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

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

**Emergency Minimum Limit or Emergency Min** means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

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

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

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

**Energy Administration Service (EAS)** is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

**Energy Efficiency** is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.
Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.


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

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

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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

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

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

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

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.
**Exempt Real-Time Generation Obligation** means that portion of a Market Participant’s Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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

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

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

**Existing Demand Resource** is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

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

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

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

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

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

**Exports** are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.
**External Market Monitor** means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

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

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

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

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

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

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

**Fast Start Generator** means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

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

**FCA Payment** is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

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

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

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

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

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


**Financial Transmission Right (FTR)** is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.
Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.


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

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.
**Forward Capacity Auction Starting Price** is calculated in accordance with Section III.13.2.4 of Market Rule 1.

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

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

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

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

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

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

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

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

**Forward Reserve Delivered Megawatts** are calculated in accordance with Section III.9.6.5 of Market Rule 1.
**Forward Reserve Delivery Period** is defined in Section III.9.1 of Market Rule 1.

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

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

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

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

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

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

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

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

**Forward Reserve Heat Rate** is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.
Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

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

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

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

Forward Reserve Offer Cap is $14,000/megawatt-month.

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

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

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

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

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

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

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

**FTR Award Financial Assurance** is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

**FTR Bid Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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

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

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

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

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

**GADS Data** means data submitted to the NERC for collection into the NERC’s Generating Availability Data System (GADS).
Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

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

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

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

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

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

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).
Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

**Hourly Adjusted Audited Demand Reduction** is calculated in accordance with Section III.13.7.1.5.10.1.2.

**Hourly Calculated Demand Resource Performance Value** means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

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

**Hourly PER** is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

**Hourly Real-Time Demand Response Resource Deviation** means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

**Hourly Real-Time Emergency Generation Resource Deviation** is calculated pursuant to Section III.13.7.1.5.8.3.1.

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

**Hub** is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.
Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

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

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

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

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

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

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

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

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.
**Incremental ARR Holder** is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

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

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

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

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

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

**Insufficient Competition** is defined in Section III.13.2.8.2 of Market Rule 1.

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

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

**Interconnection Agreement** is the “Large Generator Interconnection Agreement” or the “Small Generator Interconnection Agreement” pursuant to Schedules 22 and 23 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

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

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

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

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

**Intermittent Power Resource** is defined in Section III.13.1.2.2.2 of Market Rule 1.

**Intermittent Settlement Only Resource** is a Settlement Only Resource that is also an Intermittent Power Resource.

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

**Internal Bilateral for Market for Energy** is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.
**Internal Market Monitor** means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

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

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

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

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

ISO means ISO New England Inc.

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

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

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


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

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

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

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


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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand
Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

**Load Response Program** means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

**Load Response Program Asset** means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.
Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

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

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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

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

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.
Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

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

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

LSE means load serving entity.

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

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

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

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.
Market Credit Limit is a credit limit for a Market Participant’s Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

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

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

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


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

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

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

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

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

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource’s Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered
demand and the output of all generators located behind the asset’s end-use customer meter in the same time intervals.

**Maximum Generation** is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

**Maximum Interruptible Capacity** is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset’s peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator’s maximum possible output and its expected output when not providing demand reduction.

**Maximum Load** is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

**Maximum Net Supply** is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset’s Retail Delivery Point.

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

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

**Measurement and Verification Documents** mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

**Measurement and Verification Plan** means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

**Measurement and Verification Reference Reports** are optional reports submitted by Demand Resource suppliers 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 Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

**Measurement and Verification Summary Report** is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

**MEPCO Grandfathered Transmission Service Agreement (MGTSA)** is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.
Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource’s Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.
Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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

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

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

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

Monthly Capacity Variance means a Demand Resource’s actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource’s final Capacity Supply Obligation for the month.

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

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer’s Real-Time Generation Obligation, in MWhs.
**Monthly Real-Time Load Obligation** is the absolute value of a Customer’s hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

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

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

**MUI** is the market user interface.

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

**MW** is megawatt.

**MWh** is megawatt-hour.

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

**NCPC Charge** means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

**NCPC Credit** means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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

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

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

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

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

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

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

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

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

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

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

**Net Regional Clearing Price** is described in Section III.13.7.3 of Market Rule 1.

**Net Supply** is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.
**Net Supply Generator Asset** is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

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

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

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

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

**New Capacity Offer** is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.
New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone’s Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

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

New Capacity Show of Interest Form is described in Section III.13.1.2.1 of Market Rule 1.

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

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a
resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

**New Demand Response Asset Audit** is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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

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

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

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

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

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

**NMPTC** means Non-Market Participant Transmission Customer.
**NMPTC Credit Threshold** is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

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

**Nodal Amount** is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

**Node** is a point on the New England Transmission System at which LMPs are calculated.

**No-Load Fee** is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

**Nominated Consumption Limit** is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

**Non-Commercial Capacity**, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.B of that policy.

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

**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount)** is calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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

**Non-Hourly Charges** are defined in Section 1.3 of the ISO New England Billing Policy.
Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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

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

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

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.
**Offer Data** means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

**Offered CLAIM10** is a Supply Offer value between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

**Offered CLAIM30** is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

**Offered Full Reduction Time** is the value calculated pursuant to Section III.13.6.1.5.4.6.

**On-Peak Demand Resource** is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Open Access Same-Time Information System (OASIS)** is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission’s regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.


**Operating Authority** is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

**Operating Data** means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.
**Operating Day** means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

**Operating Reserve** means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Operations Date** is February 1, 2005.

**OTF Service** is transmission service over OTF as provided for in Schedule 20.

**Other Transmission Facility (OTF)** are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

**Other Transmission Operating Agreements (OTOA)** is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

**Other Transmission Owner (OTO)** is an owner of OTF.

**Ownership Share** is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

**Participant Expenses** are defined in Section 1 of the Participants Agreement.

**Participant Required Balance** is defined in Section 5.3 of the ISO New England Billing Policy.
Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource’s total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

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

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

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

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

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

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

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

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.
**Pool RNS Rate** is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

**Pool-Scheduled Resources** are described in Section III.1.10.2 of Market Rule 1.

**Pool Supported PTF** is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

**Pool Transmission Facility (PTF)** means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

**Poorly Performing Resource** is described in Section III.13.7.1.1.5 of Market Rule 1.

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

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

**Posturing Credit** is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.
Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor’s (S&P), Moody’s, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

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

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

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.
**Real-Time Demand Resource Dispatch Hours** means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

**Real-Time Demand Response Asset** means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant’s Real-Time Demand Response Resource.

**Real-Time Demand Response Event Hours** means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

**Real-Time Demand Response Resource** is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

**Real-Time Emergency Generation Asset** means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant’s Real-Time Emergency Generation Resource.

**Real-Time Emergency Generation Event Hours** means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.
Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

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

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

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource’s Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

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

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

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

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

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant’s Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

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

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

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant’s compensation associated with that Market Participant’s Resources’ Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.
**Real-Time Reserve Opportunity Cost** is defined in Section III.2.7A(b) of Market Rule 1.

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

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

**Reference Level** is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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

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

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.
Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

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

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

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant’s Resource as calculated by the ISO based upon that Resource’s Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit’s Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit’s Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.
**Regulation Rank Price** is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

**Regulation Requirement** is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

**Regulation Service Credit** is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

**Regulation Service Megawatts** are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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

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

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

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

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

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

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

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

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

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy
Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may
submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with
Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June
1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

**Replacement Reserve** is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

**Request for Alternative Proposals (RFAP)** is the request described in Attachment K of the OATT.

**Requested Billing Adjustment (RBA)** is defined in Section 6.1 of the ISO New England Billing Policy.

**Required Balance** is an amount as defined in Section 5.3 of the Billing Policy.

**Reseller** is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in
Section II.45.1(a) of the OATT.
**Reserve Constraint Penalty Factors (RCPFs)** are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

**Reserve Zone** is defined in Section III.2.7 of Market Rule 1.

**Reserved Capacity** is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

**Resource** means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

**Restated New England Power Pool Agreement (RNA)** is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

**Rest-of-Pool Capacity Zone** is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

**Rest of System** is an area established under Section III.2.7(d) of Market Rule 1.

**Retail Delivery Point** is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.
**Returning Market Participant** is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

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

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

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

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

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

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

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

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

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

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

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

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

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

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource’s Economic Minimum Limit; or (ii) the Resource’s Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.
Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.
**Short-Term** is a period of less than one year.

**Significantly Reduced Congestion Costs** are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

**SMD Effective Date** is March 1, 2003.

**Solutions Study** is described in Section 4.2(b) of Attachment K to the OATT.

**Special Constraint Resource (SCR)** is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

**Special Constraint Resource Service** is the form of Ancillary Service described in Schedule 19 of the OATT.

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

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

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

**Start-Up Fee** is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.
Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

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

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

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

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.
Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

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

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

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

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.
System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer’s Service Agreement.

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

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

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

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

Technical Committee is defined in Section 8.2 of the Participants Agreement.
Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

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

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.
**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

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

**Time-on-Regulation Credit** is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

**Time-on-Regulation Megawatts** is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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

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

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

**Total Blackstart Service Payments** is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.
**Total Negative Hourly Demand Response Resource Deviation** means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

**Total Positive Hourly Demand Response Resource Deviation** means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

**Total System Capacity** is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

**Transaction Unit (TU)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

**Transition Period**: The six-year period commencing on March 1, 1997.

**Transmission Charges**, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

**Transmission Congestion Credit** means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

**Transmission Congestion Revenue** is defined in Section III.5.2.5(a) of Market Rule 1.

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

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.
Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

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

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

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

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

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

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

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

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

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

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

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

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

UDS is unit dispatch system software.

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

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.
Unrated means a Market Participant that is not a Rated Market Participant.

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

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

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

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

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

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

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

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

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.
VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

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

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.
1.2  Rules of Construction; Definitions

1.2.1  Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

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

I.2.2. Definitions:

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

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

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

**Adjusted Audited Demand Reduction** is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

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

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

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

**Administrative Costs** are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.
Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

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

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

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

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

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

AGC is automatic generation control.

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

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

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

Alternative Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.
Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

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

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

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

Annualized FCA Payment is used to determine a resource’s availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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

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

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.
Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO’s website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO’s dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.
**Auction Revenue Right Holder (ARR Holder)** is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

**Audited Demand Reduction** is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

**Audited Full Reduction Time** is the Offered Full Reduction Time associated with the Demand Response Resource’s most recent audit.

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

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

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

**Average Hourly Load Reduction** is either: (i) the sum of the Demand Resource’s electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource’s electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource’s electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource’s Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.
**Average Hourly Output** is either: (i) the sum of the Demand Resource’s electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource’s electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource’s Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

**Average Monthly PER** is calculated in accordance with Section III.13.7.1.2.22.7.1.1.2(a) of Market Rule 1.

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

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

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

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

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

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

**Blackstart CIP Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station’s costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

**Blackstart CIP O&M Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station’s operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

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

**Blackstart O&M Payment** is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource’s operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

**Blackstart Service** is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses “System Restoration and Planning Service” under the predecessor version of Schedule 16.

**Blackstart Service Commitment** is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New
England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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

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

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

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

**Blackstart Station-specific Rate Capital Payment** is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

**Block** is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for the
day); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy
(Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with
respect to Increment Offers administered by the ISO, a quantity with a related price for Energy
(Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5)
with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy
(Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with
respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy
(Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7)
with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a
related price (for Capacity Commitment Periods commencing on or after June 1, 2017, Demand
Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

**Cancellation Fee** is defined in Section III.1.10.2(d).

**Cancelled Start Credit** is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule
1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were
scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by
the ISO prior to their assigned commitment time.

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

**Capability Year** means a year’s period beginning on June 1 and ending May 31.

**Capacity Acquiring Resource** is a resource that is seeking to acquire a Capacity Supply Obligation
through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.
Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1, beginning on June 1, 2018 pursuant to rules filed with the Commission on December 31, 2013.

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

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

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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

Capacity Clearing Price Floor is described in Section III.13.2.7.

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

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

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

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant’s Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.53.1 of Market Rule 1.
**Capacity Load Obligation Acquiring Participant** is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

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

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

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

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

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

**Capacity Performance Payment** is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1, beginning on June 1, 2018 pursuant to rules filed with the Commission on December 31, 2013.

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

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

**Capacity Rationing Rule** addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.
Capacity Requirement is described in Section III.13.7.53.1 of Market Rule 1.

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

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

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

Capacity-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder’s entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.1.4.27.1.5 of Market Rule 1.

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

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.
**CARL Data** is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

**Carried Forward Excess Capacity** is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

**Category A Designated Blackstart Resource** is a Designated Blackstart Resource that has committed to provide Blackstart Service under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

**Category B Designated Blackstart Resource** is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

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

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

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

**Claimed Capability Audit** is performed to determine the real power output capability of a Generator Asset.

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

**Coincident Peak Contribution** is a Market Participant’s share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year’s annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.
**Commercial Capacity**, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

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

**Common Costs** are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

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

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

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

**Conditional Qualified New Generating Capacity Resource** is defined in Section III.13.1.2.3(f) of Market Rule 1.

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

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

**Congestion** is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.
Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

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

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

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

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

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

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

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

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

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

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

**Cost of New Entry (CONE)** is the value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

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

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

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

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

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

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

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

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

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

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

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

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

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

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.
**Day-Ahead Loss Charges or Credits** is defined in Section III.3.2.1(h) of Market Rule 1.

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

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

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

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

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

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

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

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

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

**Demand Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time

**Demand Reduction Offer** is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

**Demand Reduction Threshold Price** is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

**Demand Reduction Value** is the quantity of reduced demand calculated pursuant to Section III.13.1.37.1.5.3 of Market Rule 1.

**Demand Resource** is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

**Demand Resource Commercial Operation Audit** is an audit initiated pursuant to Section III.13.6.1.5.4.4.

**Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO’s most recent next-day forecast.

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

**Demand Resource Operable Capacity Analysis** means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

**Demand Resource Performance Incentives** means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

**Demand Resource Performance Penalties** means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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

**Demand Response Asset** is the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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

**Demand Response Baseline** is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.
Demand Response Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

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

Demand Response Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start reducing demand.

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

Demand Response Resource Start-Up Time is the time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.
**Designated Blackstart Resource** is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

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

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

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

**Desired Dispatch Point (DDP)** is the Dispatch Rate expressed in megawatts.

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

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

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

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

**Dispatch Rate** means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

**Dispatch Zone** means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

**Dispatchable Asset Related Demand** is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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

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

**Distributed Generation** means generation resources directly connected to end-use customer load and located behind the end-use customer’s meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

**Do Not Exceed Dispatch Point** is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

**DR Auditing Period** is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

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

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

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

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

**Early Amortization Working Capital Charge (EAWCC)** is defined in Section IV.B.2 of the Tariff.
Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource’s Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits.

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

EFT is electronic funds transfer.

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade),
and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

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

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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

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

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

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

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

**Emergency Minimum Limit or Emergency Min** means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

**EMS** is energy management system.

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

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

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

**Energy Administration Service (EAS)** is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of
Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

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

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


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

**Energy Offer Cap** is $1,000/MWh.

**Energy Offer Floor** is negative $150/MWh.

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

**Enrolling Participant** is the Market Participant that registers Customers for the Load Response Program.

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

**Equivalent Demand Forced Outage Rate (EFORd)** means the portion of time a unit is in demand, but is unavailable due to forced outages.
**Estimated Capacity Load Obligation** is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

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

**Estimated Net Regional Clearing Price (ENRCP)** is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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

**Exempt Real-Time Generation Obligation** means that portion of a Market Participant’s Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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

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

**Existing Capacity Resource** is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

**Existing Demand Resource** is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.
Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

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

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

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

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

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

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

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

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

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.
Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

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

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

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

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

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

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


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


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

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


Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.
**Forecast Hourly Demand Reduction** means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

**Formal Warning** is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

**Formula-Based Sanctions** are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

**Forward Capacity Auction (FCA)** is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

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

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

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

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

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

**Forward Reserve Auction Offers** are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.
**Forward Reserve Charge** is a Market Participant’s share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forward Reserve Offer Cap is $14,000/megawatt-month.

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

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.
Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource’s capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

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

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

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

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

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.
**FTR Holder** is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

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

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

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

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

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

**Generating Capacity Resource** means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

**Generator Asset** is a generator that has been registered in accordance with the Asset Registration Process.

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

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

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

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

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

**Governance Participant** is defined in the Participants Agreement.

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

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

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

**Grandfathered Intertie Agreement (GIA)** is defined pursuant to the TOA.
Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

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

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

Hourly Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.
Hourly PER is calculated in accordance with Section III.13.7.1.2.7.1.1.1(a) of Market Rule 1.

**Hourly Real-Time Demand Response Resource Deviation** means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

**Hourly Real-Time Emergency Generation Resource Deviation** is calculated pursuant to Section III.13.7.1.5.8.3.1.

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

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

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

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

**Import Capacity Resource** means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.
Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

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

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

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

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

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

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

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

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

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

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.
Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

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

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

Interconnection Agreement is the “Large Generator Interconnection Agreement” or the “Small Generator Interconnection Agreement” pursuant to Schedules 22 and 23 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

Interconnection Procedure is the “Large Generator Interconnection Procedures” or the “Small Generator Interconnection Procedures” pursuant to Schedules 22 and 23 of the ISO OATT.

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

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

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

Interest is interest calculated in the manner specified in Section II.8.3.
**Interface Bid** is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

**Intermittent Power Resource** is defined in Section III.13.1.2.2.2 of Market Rule 1.

**Intermittent Settlement Only Resource** is a Settlement Only Resource that is also an Intermittent Power Resource.

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

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

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

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

**Investment Grade Rating**, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant’s or Non-Market Participant Transmission Customer’s senior unsecured debt from one or more of the Rating Agencies.
**Invoice** is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

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

**ISO** means ISO New England Inc.

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

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

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


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

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

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

**ISO New England Information Policy** is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.
ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.


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

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


ITC Agreement is defined in Attachment M to the OATT.

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

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

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

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.
Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

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

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

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.
Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

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

Local Area Facilities are defined in the TOA.

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

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

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

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

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

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.
Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

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

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

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

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

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

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

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

**Location** is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

**Locational Marginal Price (LMP)** is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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

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

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

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

**Loss of Load Expectation (LOLE)** is the probability of disconnecting non-interruptible customers due to a resource deficiency.
Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

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

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

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

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

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

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

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

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

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


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

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

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

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

**Material Adverse Change** is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant’s or Non-Market Participant Transmission Customer’s credit default spreads; or a significant change in market capitalization.
**Material Adverse Impact** is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a “material adverse impact” on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

**Maximum Capacity Limit** is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

**Maximum Consumption Limit** is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource’s Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

**Maximum Facility Load** is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset’s end-use customer meter in the same time intervals.

**Maximum Generation** is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

**Maximum Interruptible Capacity** is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset’s peak load less its uninterruptible load. For assets that deliver reductions through the use of
generation, the Maximum Interruptible Capacity is the difference between the generator’s maximum possible output and its expected output when not providing demand reduction.

**Maximum Load** is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

**Maximum Net Supply** is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset’s Retail Delivery Point.

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

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

**Measurement and Verification Documents** mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.
Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers 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 Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.
Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource’s Offer Data.

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

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

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.
Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource’s Demand Reduction Offer.

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

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

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

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

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

Monthly Capacity Variance means a Demand Response’s actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Response’s final Capacity Supply Obligation for the month.

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

Monthly PER is calculated in accordance with Section III.13.7.1.2.22.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer’s Real-Time Generation Obligation, in MWhs.
**Monthly Real-Time Load Obligation** is the absolute value of a Customer’s hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

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

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

**MUI** is the market user interface.

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

**MW** is megawatt.

**MWh** is megawatt-hour.

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

**NCPC Charge** means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

**NCPC Credit** means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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

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

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

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

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

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

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

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

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

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

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

**Net Regional Clearing Price** is described in Section III.13.7.53 of Market Rule 1.

**Net Supply** is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.
**Net Supply Generator Asset** is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

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

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

**Network Resource** is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

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

**New Capacity Offer** is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.
New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone’s Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

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

New Capacity Show of Interest Form is described in Section III.13.1.2.1 of Market Rule 1.

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

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a
resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but
does not have a winter audit value and a summer audit value.

**New Demand Response Asset Audit** is an audit of a New Demand Response Asset performed pursuant
to Section III.13.6.1.5.4.8.

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

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

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

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

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

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

**NMPTC** means Non-Market Participant Transmission Customer.
**NMPTC Credit Threshold** is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

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

**Nodal Amount** is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

**Node** is a point on the New England Transmission System at which LMPs are calculated.

**No-Load Fee** is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

**Nominated Consumption Limit** is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.53.1.3.

**Non-Commercial Capacity**, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.B of that policy.

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

**Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount)** is calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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

**Non-Hourly Charges** are defined in Section 1.3 of the ISO New England Billing Policy.
Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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

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

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

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.
Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission’s regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.
**Operating Day** means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

**Operating Reserve** means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

**Operations Date** is February 1, 2005.

**OTF Service** is transmission service over OTF as provided for in Schedule 20.

**Other Transmission Facility (OTF)** are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

**Other Transmission Operating Agreements (OTOA)** is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

**Other Transmission Owner (OTO)** is an owner of OTF.

**Ownership Share** is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

**Participant Expenses** are defined in Section 1 of the Participants Agreement.

**Participant Required Balance** is defined in Section 5.3 of the ISO New England Billing Policy.
Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource’s total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1 of Market Rule 1.

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

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

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

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

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

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

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

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

**Point-To-Point Service** is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

**Pool-Planned Unit** is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

**Pool PTF Rate** is the transmission rate determined in accordance with Schedule 8 to the OATT.
**Pool RNS Rate** is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

**Pool-Scheduled Resources** are described in Section III.1.10.2 of Market Rule 1.

**Pool Supported PTF** is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

**Pool Transmission Facility (PTF)** means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

**Poorly Performing Resource** is described in Section III.13.7.1.5 of Market Rule 1.

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

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

**Posturing Credit** is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

**Qualified Reactive Resource(s)** is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.
Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor’s (S&P), Moody’s, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

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

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

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.
**Real-Time Demand Resource Dispatch Hours** means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

**Real-Time Demand Response Asset** means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant’s Real-Time Demand Response Resource.

**Real-Time Demand Response Event Hours** means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

**Real-Time Demand Response Resource** is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

**Real-Time Emergency Generation Asset** means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant’s Real-Time Emergency Generation Resource.

**Real-Time Emergency Generation Event Hours** means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.
**Real-Time Emergency Generation Resource** is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

**Real-Time Energy Market** means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

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

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

**Real-Time High Operating Limit** is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource’s Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

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

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

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

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

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant’s Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

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

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

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant’s compensation associated with that Market Participant’s Resources’ Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.
**Real-Time Reserve Designation** is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

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

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

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

**Reference Level** is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Re-Offer Period** is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2017, revised Demand Reduction Offers associated with Demand Response Resources.

**Replacement Reserve** is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

**Request for Alternative Proposals (RFAP)** is the request described in Attachment K of the OATT.

**Requested Billing Adjustment (RBA)** is defined in Section 6.1 of the ISO New England Billing Policy.

**Required Balance** is an amount as defined in Section 5.3 of the Billing Policy.

**Reseller** is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.
Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.
**Retail Delivery Point** is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system.

If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

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

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

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

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

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

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

**RTO** is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

**Same Reserve Zone Export Transaction** is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

**Sanctionable Behavior** is defined in Section III.B.3 of Appendix B of Market Rule 1.
Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in
the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset’s Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand’s Minimum Consumption Limit.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected

**Shortage Event** is defined in Section III.13.7.1.1.1 of Market Rule 1.

**Shortage Event Availability Score** is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

**Shortfall Funding Arrangement**, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

**Short-Term** is a period of less than one year.

**Significantly Reduced Congestion Costs** are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

**SMD Effective Date** is March 1, 2003.

**Solutions Study** is described in Section 4.2(b) of Attachment K to the OATT.

**Special Constraint Resource (SCR)** is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

**Special Constraint Resource Service** is the form of Ancillary Service described in Schedule 19 of the OATT.

**Specified-Term Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).
**Standard Blackstart Capital Payment** is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

**Start-of-Round Price** is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

**Start-Up Fee** is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

**Start-Up Time** is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

**State Estimator** means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

**Statements**, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

**Static De-List Bid** is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

**Station** is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

**Station Going Forward Common Costs** are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.
**Station-level Blackstart O&M Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Specified-Term Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Station-level Standard Blackstart Capital Payment** is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

**Successful FCA** is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

**Summer ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1 of Market Rule 1.

**Summer Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

**Summer Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

**Supplemental Availability Bilateral** is described in Section III.13.5.3.2 of Market Rule 1.

**Supplemental Capacity Resources** are described in Section III.13.5.3.1 of Market Rule 1.

**Supplemented Capacity Resource** is described in Section III.13.5.3.2 of Market Rule 1.

**Supply Offer** is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant’s Offer Data.
Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity’s assets less the
following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity’s intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.
**Thirty-Minute Operating Reserve (TMOR)** means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

**Thirty-Minute Operating Reserve Service** is the form of Ancillary Service described in Schedule 7 of the OATT.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart O&M Payment** is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.
Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.


Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.
**Transmission Credit Limit** is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

**Transmission Credit Test Percentage** is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

**Transmission Customer** is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

**Transmission Default Amount** is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

**Transmission Default Period** is defined in Section 3.4.f of the ISO New England Billing Policy.

**Transmission Late Payment Account** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Account Limit** is defined in Section 4.2 of the ISO New England Billing Policy.

**Transmission Late Payment Charge** is defined in Section 4.1 of the ISO New England Billing Policy.

**Transmission, Markets and Services Tariff (Tariff)** is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.
Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.
Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.
**Updated Measurement and Verification Plan** is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

**VAR CC Rate** is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Payment** is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

**VAR Service** is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

**Virtual Requirements** are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

**Volt Ampere Reactive (VAR)** is a measurement of reactive power.

**Volumetric Measure (VM)** is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

**Winter ARA Qualified Capacity** is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

**Winter Capability Period** means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

**Winter Intermittent Reliability Hours** are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.
Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.
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 Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority’s Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority’s Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.
Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section
I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule I 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, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a “Related Transaction”), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;
(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;
(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.
III.1.5.1 Claimed Capability Audits.
III.1.5.1.1 General Audit Requirements.

(a) Three types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset’s ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.
(ii) A Seasonal Claimed Capability Audit determines a Generator Asset’s capability to perform under specified summer and winter conditions for a specified duration.
(iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset’s Establish Claimed Capability Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility’s Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(b) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(c) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.
(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.

(f) To conduct an Establish Claimed Capability Audit, the ISO shall:
   (i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.
   (ii) Ensure that the Generator Asset is Self-Scheduled for the time to ramp to its full capability and for the duration of the Establish Claimed Capability Audit.
   (iii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset’s net output to increase from the current operating level to its Real-Time High Operating Limit.
   (iv) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Claimed Capability Audit Duration (Hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Turbine (Includes Nuclear)</td>
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<td>4</td>
</tr>
<tr>
<td>Pressurized Fluidized Bed Combustion</td>
<td>4</td>
</tr>
<tr>
<td>Combustine Gas Turbine</td>
<td>1</td>
</tr>
</tbody>
</table>
III.1.5.1.3. **Seasonal Claimed Capability Audits.**

(a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset’s Seasonal Claimed Capability Audit obligation.

(c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(d) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
(e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(h) The Seasonal Claimed Capability Audit value shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Claimed Capability Audit Duration (Hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Turbine (Includes Nuclear)</td>
<td>2</td>
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<td>2</td>
</tr>
<tr>
<td>Integrated Coal Gasification Combustion Cycle</td>
<td>2</td>
</tr>
<tr>
<td>Pressurized Fluidized Bed Combustion</td>
<td>2</td>
</tr>
<tr>
<td>Combustion Gas Turbine</td>
<td>1</td>
</tr>
<tr>
<td>Internal Combustion Engine</td>
<td>1</td>
</tr>
<tr>
<td>Hydraulic Turbine-Reversible</td>
<td>2</td>
</tr>
<tr>
<td>Hydro-Conventional Weekly</td>
<td>2</td>
</tr>
</tbody>
</table>

(j) A Generator Asset that is on a planned outage that was approved in the ISO’s annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal
Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset’s location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset’s location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.
A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

### III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.
(d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective seven Business Days following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

(ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset’s net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

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</thead>
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<td>2</td>
</tr>
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<td>Hydro-Conventional Daily Pondage</td>
<td>2</td>
</tr>
<tr>
<td>Hydro-Conventional Run of River</td>
<td></td>
</tr>
<tr>
<td>Hydro-Conventional Weekly</td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>2</td>
</tr>
<tr>
<td>Photovoltaic</td>
<td></td>
</tr>
<tr>
<td>Fuel Cell</td>
<td></td>
</tr>
</tbody>
</table>
(a) The ISO may perform an audit of any Supply Offer parameter that impacts the ability of a Generator Asset to provide real-time energy or reserves.

(b) Audits shall be performed using the following methods:

(i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5 of Market Rule 1.

(vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5 of Market Rule 1.

(vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second ISO-issued electronic Dispatch Instructions.

(c) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator performance in response to ISO Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator performance in response to ISO Dispatch Instructions.

(d) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset’s net output to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset for the parameters being audited.

(e) To the extent that the audit results indicate a Market Participant is providing Supply Offer parameter values that are not representative of the actual capability of the Generator Asset, Supply Offer parameter values for the Generator Asset shall be restricted to the value that is supported by the audit.

(f) In the event that a Generator Asset has had a Supply Offer parameter value restricted:
(i) The Lead Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the Supply Offer parameter’s value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the Supply Offer parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the Supply Offer parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and

Modify the Supply Offer parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.6 [Reserved.]
III.1.6.1 [Reserved.]
III.1.6.2 [Reserved.]
III.1.6.3 [Reserved.]


III.1.7 General.
III.1.7.1 Provision of Market Data to the Commission.
The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission’s regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.
A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.
(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.
(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule 1 and the ISO New England Manuals.
III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) 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.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) netmetered 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 [Reserved.]
III.1.7.13 [Reserved.]
III.1.7.14 [Reserved.]
III.1.7.15 [Reserved.]
III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.
The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. 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 ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 [Reserved.]

III.1.7.19 Ramping.
A generating unit dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit’s megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in Appendix B.
III.1.7.19A **Real-Time Reserve.**

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 **Information and Operating Requirements.**

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO’s directives to start, shutdown or change output levels of generating units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment is operated with control equipment functioning as specified in the ISO New England Manuals & ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.
(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant’s ability to procure fuel and physical limitations that could reduce Resource output for the pertinent Operating Day.

| III.1.8 | [Reserved.] |
| III.1.9 | Pre-scheduling. |
| III.1.9.1 | [Reserved.] |
| III.1.9.2 | [Reserved.] |
| III.1.9.3 | [Reserved.] |
| III.1.9.4 | [Reserved.] |
| III.1.9.5 | [Reserved.] |
| III.1.9.6 | [Reserved.] |

III.1.9.7 Market Participant Responsibilities.
Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant’s Offer Data that does not conform to the Market Participant’s specification on file with the ISO.

| III.1.9.8 | [Reserved.] |
III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

   (i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

   (ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area.
Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO’s forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with notification time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants’ binding Supply Offers for such units, as submitted in accordance with Section 1.10.1A(f), for such periods and the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and such Resources shall be treated as Pool-Scheduled Resources and shall be eligible to receive NCPC Credits under Section III.3.2.3 in accordance with the binding Supply Offers submitted.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant’s intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market
Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.
(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Operating Reserve or other services as applicable, for the following Operating Day.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource or Load Asset and energy for each hour in the offer period;

(ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers. Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly;

(iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

(v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource’s Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be
revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource’s Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its Minimum Run Time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource’s Minimum Run Time; and

(ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.

(c) [Reserved.]

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the
applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO’s estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits and Economic Minimum Limits are not used in determining the amount of energy (MW) in each marginal Supply Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits and Economic Minimum Limits.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.
(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, and the specified operating characteristics, offered by Market Participants to the ISO by the offer deadline specified in Section III.1.10.1A.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees and No-Load Fee, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized (“Cancellation Fee”).

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

(f) Eligibility for NCPC in the Day-Ahead Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in Appendix F of this Market Rule 1.
(g) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in Appendix F of this Market Rule 1.

(h) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in Appendix F of this Market Rule 1.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in Appendix F of this Market Rule 1.

III.1.10.3 Self-Scheduled Resources.
A Resource that is Self-Scheduled shall be governed by the following principles and procedures.

(a) [Reserved.]

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.
(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;
(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource’s ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

**III.1.10.7 External Transactions.**

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.


(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;
(3) The External Node associated with the cleared Export Bid or Administrative Export De-
List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity 
Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or 
Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy 
Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy 
Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in 
accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead 
Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to 
an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an 
Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the 
megawatt amount of the External Transaction is less than or equal to the megawatt amount of the 
cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with 
the Export Bid or Administrative Export De-List Bid is located outside the import-constrained 
Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy 
Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy 
Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in
accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;
(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction’s export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges
described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

(iii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iv) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A  Coordinated External Transactions.
The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location and the Northport-Norwalk external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the period for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization
(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO’s interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in
the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the “foregone” production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term “b.” The difference in bid production cost savings between (i) and (ii) above will reveal the “foregone” bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term “a.”

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

\[ \frac{b}{a} \]

If, the ratio \( \frac{b}{a} \) is greater than 60% and \( b \) is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1..10.7.B(b)(1), is greater than 60% and \( b \) is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.
(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

\[ \frac{b}{a} \]

If the ratio \( \frac{b}{a} \) is greater than 60% and \( b \) is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio \( \frac{b}{a} \) is greater than 60% and \( b \) is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.
(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the Design Basis Document for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing
The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.
(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-
Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO’s forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall
exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.
(d) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit.

(e) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(b), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(f) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant’s Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or
Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary:
(a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy,
reserves, and other services required by the Market Participants and the operation of the New England
Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency
support within the New England Control Area; and (c) to minimize unscheduled interchange that is not
frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.
In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control
Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative
Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and
(ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.
(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to
minimize the as-bid production cost for the New England Control Area. In implementing the use of
Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of
operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with
the dynamic load-following requirements of the New England Control Area and the availability of other
Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and
the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the
dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate
signals and instructions to the entity controlling such Resources, in accordance with the ISO New
England Manuals and ISO New England Administrative Procedures. Each Market Participant shall
ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market
Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant’s operational related Offer Data
if the ISO observes that the Market Participant’s Resource is not operating in accordance with such Offer
Data. The ISO shall modify such operational related Offer Data based on observed performance and such
modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to
be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England
Manuals, and the results of the test justify a change to the Market Participant’s Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant’s Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO’s modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.
If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 [Reserved.]

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.
Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource’s output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource’s output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.
SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION
APPENDIX A
MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1 Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1  Mission Statement.
The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant’s behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this Appendix A.

III.A.1.2  Structure and Oversight.
The market monitoring and mitigation functions contained in this Appendix A shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this Appendix A. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor’s functions, the External Market Monitor shall have, and the ISO’s contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor’s scope of work shall be subject to prior Commission approval.

III.A.1.3  Data Access and Information Sharing.
The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this Appendix A.
This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission’s jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO’s electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this Appendix A, the provisions of Appendix A shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either Appendix A or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this Appendix A are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.


The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this Appendix A). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its
identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission’s Office of Enforcement of instances in which a Market Participant’s behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this Appendix A, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO’s actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission’s Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this Appendix A, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England
Markets, including the adequacy of this Appendix A, in accordance with the provisions of Section III.A.17 of this Appendix A.

c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission’s Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this Appendix A, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this Appendix A.

f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

g) Review the ISO’s filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor’s assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this Appendix A, as appropriate.

h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this Appendix A, the Internal Market Monitor shall perform the following functions:
(a) Maintain Appendix A and consider whether Appendix A requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this Appendix A.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this Appendix A.

(d) Identify and notify the Commission’s Office of Enforcement staff of instances in which a Market Participant’s behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this Appendix A.

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO’s actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission’s Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this Appendix A, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor’s functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this Appendix A.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided
Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this Appendix A.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this Appendix A are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this Appendix A.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this Appendix A.

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend Appendix A as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of
the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;
(ii) Conduct and market outcomes that are inconsistent with competitive markets;
(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
(iv) Actions in one market that affect price in another market;
(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this Appendix A, interfere with efficient market operation, both short-run and long-run; and
(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this Appendix A. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this Appendix A. If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with Appendix B of this Market Rule I.
(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. **Overview of the Internal Market Monitor’s Mitigation Functions.**

III.A.2.4.1. **Purpose.**
The mitigation measures set forth in this *Appendix A* for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule I (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this *Appendix A*. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this *Appendix A*, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO’s authority to evaluate Market Participant behavior for potential sanctions under *Appendix B* of this Market Rule 1.

III.A.2.4.2. **Conditions for the Imposition of Mitigation.**

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11. below:

(b) Notwithstanding the foregoing or any other provision of this *Appendix A*, and as more fully described in Section III.B.3.2.6 of *Appendix B* to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3 **Applicability.**
Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.
III.A.2.4.4 Mitigation Not Provided for Under This Appendix A.
The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this Appendix A, it may make a filing under §205 of the Federal Power Act (“§205”) with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure.

III.A.2.4.5 Duration of Mitigation.
Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this Appendix A or in Appendix B to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.
Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1 Consultation Prior to Offer.
If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this Appendix A, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least one hour prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the Real-Time Energy Market, the Market Participant must contact the Internal Market Monitor at least one hour prior to the posting of the Day-Ahead Energy Market results. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market Participant’s submission of the offer.

Any changes to fuel prices shall not be subject to the consultation provisions of this Section III.A.3.1. If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this Appendix A for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of cost-based Reference Levels, pursuant to Section III.A.7.5 below, unless a Market Participant notifies the Internal Market Monitor that the Resource will be operating on the higher cost fuel type.

If a Market Participant provides such notification, the Internal Market Monitor will use the higher cost fuel type in the calculation of the cost-based Reference Levels for the resource. Within five business days of a request by the Internal Market Monitor, the Market Participant must:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.
If the Market Participant fails to provide supporting information within five business days of a request by the Internal Market Monitor, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

III.A.3.3. Market Participant Access to its Reference Levels.
The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant’s Supply Offers through the MUI. The Reference Levels will be made available on a daily basis. The Market Participant shall not modify such Reference Levels in the ISO’s or Internal Market Monitor’s systems.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource’s Supply Offer, whenever the Market Participant’s expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

   (i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

   (ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

   (iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource’s Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource’s Supply Offer plus $2.50/MMbtu.

(b) Within five business days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with (i) an invoice for the fuel utilized or (ii) a quote from a named supplier
or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm’s length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price may be no greater than 110% of the fuel price reflected on the submitted invoice for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder.

(c) The Supply Offers for the associated Resource may be no greater than 110% and no less than 90% of the Reference Level calculated with the submitted fuel price.

(d) If, within a 12 month period, the requirements in sub-sections (b) or (c) are not met for a Resource, then a fuel price adjustment shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-sections (b) or (c) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

<table>
<thead>
<tr>
<th>Number of Incidents</th>
<th>Months Precluded (starting from most-recent incident)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>2 or more</td>
<td>6</td>
</tr>
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III.A.4.1. Identification of Conduct Inconsistent with Competition. This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor’s ability to refer potential instances of physical withholding to the Commission.
Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource’s capacity;
(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant’s total capacity for Market Participants with more than one Resource; or
(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO’s Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource’s available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.
A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.
Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.
Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.
Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.
Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;
(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource’s Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;
(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset’s Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five business days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior.

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.1 “General Threshold Energy Mitigation” and Section III.A.5.3 “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.5.2 “Constrained Area Threshold Energy Mitigation” and Section III.A.5.4 “Constrained Area Threshold 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. 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 in the Day-Ahead Energy Market is any of the 24 hours for which pivotal supplier calculations are made. 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 the clearing of the Day-Ahead Energy Market, prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

III.A.5.2.2. Constrained Area Test.
A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource’s Node exceeds the LMP at the Hub by more than $25/MWh.

The price impact for the purposes of Section III.A.5.5.1 “General Threshold Energy Mitigation” compares two LMPs at a Resource’s Node. The first LMP is calculated based on the Supply Offers submitted for all Resources. The second LMP is calculated through a simulation of the Day-Ahead Energy Market with the offer blocks associated with conduct violations of the pivotal supplier’s Resources set to their Reference Levels.

A Supply Offer shall be determined to have no price impact for the purposes of Section III.A.5.5.1 “General Threshold Energy Mitigation” if:

(a) the first LMP at the Resource’s Node is less than the impact threshold, or;

(b) the first LMP minus the Resource’s Reference Level for each offer block is less than the impact threshold.

The price impact for the purposes of Section III.A.5.5.2 “Constrained Area Energy Mitigation” is equal to the difference between the LMP at the Resource’s Node and the LMP at the Hub.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource’s Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers submitted by a Lead Market Participant that is determined to be a pivotal supplier.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater
than 200% or $100/MWh, whichever is lower as determined by the day-ahead or real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.
If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.
Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.
A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.
A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.
If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. General Threshold Commitment Mitigation.

III.A.5.5.3.1. Applicability.
Mitigation pursuant to this section shall be applied to any Resource whose Lead Market Participant is determined to be a pivotal supplier.
III.A.5.5.3.2. Conduct Test.
A Resource shall fail the conduct test for general threshold commitment mitigation if any Start-Up Fee or No-Load Fee exceeds the Reference Level for that fee by 200% or more.

III.A.5.5.3.3. Consequence of Failing Conduct Test.
If a Resource fails the general threshold commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters of its Supply Offer set to their Reference Levels, including all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.4. Constrained Area Commitment Mitigation.

III.A.5.5.4.1. Applicability.
Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.
A Resource shall fail the conduct test for constrained area commitment mitigation if any Start-Up Fee or the No-Load Fee is submitted with an increase greater than 25% above the Reference Level.

III.A.5.5.4.3. Consequence of Failing Test.
If a Supply Offer fails the constrained area commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all energy offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Local Reliability Commitment Mitigation.

III.A.5.5.5.1. Applicability.
Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are committed to provide, or Resources that are required to remain online to provide, one or more of the following:

(a) local first contingency protection or local second contingency protections;
(b) VAR or voltage support; or
(c) Special Constraint Resource Service

III.A.5.5.2. Minimum Run Time Conduct Test.
All financial parameters of Supply Offers will be evaluated using the following formula:

\[
(\text{Low Load Cost Minimum Run Time at Offer} - \text{Low Load Cost Minimum Run Time at Reference Level}) = \text{Commitment Cost Threshold}
\]

Where,

\[
\text{Commitment Cost Threshold} = 0.1 \times \text{Low Load Cost at Reference Level.}
\]

\[
\text{Low Load Cost} = \text{the cost of operating the Resource at its Economic Minimum Limit calculated using the following formula:}
\]

\[
(\text{Cold Start-Up Fee} + (\text{No Load Fee} \times \text{Minimum Run Time}) + (\text{Price of Energy at Economic Minimum Limit} \times \text{Economic Minimum Limit} \times \text{Minimum Run Time}))
\]

\[
\text{Low Load Cost Minimum Run Time at Offer} = \text{Low Load Cost calculated with financial parameters of the Supply Offer.}
\]

\[
\text{Low Load Cost Minimum Run Time at Reference Level} = \text{Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.}
\]

\[
\text{Price of Energy at Economic Minimum Limit} = \text{the price for energy at the Resource’s Economic Minimum Limit.}
\]
For Low Load Cost Minimum Run Time at Offer, the price for energy is the energy price parameter from the Supply Offer. For Low Load Cost Minimum Run Time at Reference Level, the Reference Level of the offer block at Economic Minimum Limit is used.

If a Resource’s combined Minimum Run Time and Minimum Down Time exceed 24 hours, then the conduct test will use the greater of 24 hours or the Resource’s Minimum Run Time for the Minimum Run Time.

If the (Low Load Cost Minimum Run Time at Offer – Low Load Cost Minimum Run Time at Reference Level) is greater than the Commitment Cost Threshold, then the conduct test is violated.

**III.A.5.5.5.3. Actual Run Time Conduct Test.**

If the Supply Offer for a Resource does not violate the conduct test in Section III.A.5.5.5.2, then all financial parameters of the Supply Offer will be evaluated using the following formula:

\[
(Low \text{ Load Cost Actual Run Time at Offer} - Low \text{ Load Cost Actual Run Time at Reference Level}) = < \text{Commitment Cost Threshold}
\]

Where,

\[
\text{Commitment Cost Threshold} = 0.1 \text{ times Low Load Cost Actual Run Time at Reference Level.}
\]

Low Load Cost Actual Run Time = the cost of operating the Resource at its Economic Minimum Limit calculated using the following formula:

\[
\text{Cold Start-Up Fee} + (\text{No Load Fee} \times \text{actual local reliability run time}) + (\text{Price of Energy at Economic Minimum Limit} \times \text{Economic Minimum Limit} \times \text{actual local reliability run time}),
\]

where

actual local reliability run time is the number of hours the Resource was operated in the Real-Time Energy Market to provide one or more of the services specified in Section III.A.5.5.5.1.
Low Load Cost Actual Run Time at Offer = Low Load Cost Actual Run Time calculated with financial parameters of the Supply Offer.

Low Load Cost Actual Run Time at Reference Level = Low Load Cost Actual Run Time calculated with the financial parameters of the Supply Offer set to Reference Levels.


For Low Load Cost Actual Run Time at Offer, the price for energy is the energy price parameter from the Supply Offer. For Low Load Cost Actual Run Time at Reference Level, the Reference Level of the offer block at Economic Minimum Limit is used.

If the (Low Load Cost Actual Run Time at Offer – Low Load Cost Actual Run Time at Reference Level) is greater than the Commitment Cost Threshold, then the conduct test is violated.

III.A.5.5.5.4. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment minimum run time conduct test specified in Section III.A.5.5.5.2, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

If a Supply Offer fails the local reliability commitment actual run time conduct test specified in Section III.A.5.5.5.3, then all financial parameters of the Supply Offer are set to their Reference Level for purposes of calculating Day-Ahead Energy Market and Real-Time Energy Market revenues.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Threshold Energy Mitigation” is in effect for the following duration:
(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:
   (i) for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,
   (ii) for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market, mitigation is in effect in each hour in which the impact test is violated.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.3 “General Threshold Commitment Mitigation”, III.A.5.5.4 “Constrained Area Commitment Mitigation”, or III.A.5.5.5 “Local Reliability Commitment Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts either;
   a. on the first hour a Resource is directed to remain on-line by the ISO or;
   b. in all other cases, at the time of the decision to commit the Resource.

(b) in the Day-Ahead Energy Market, mitigation starts at the beginning of the Operating Day, and;

(c) for both the Real-Time Energy Market and Day-Ahead Energy Market, mitigation remains in effect:
   (i) for mitigation imposed pursuant to Sections III.A.5.5.3 or III.A.5.5.4, through the end of the Resource’s Minimum Run Time; and,
   (ii) for mitigation imposed pursuant to Section III.A.5.5.5, through the end of the Resource’s Minimum Run Time or through the end of the period that the Resource is needed for reliability, whichever is later.

III.A.5.8. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five business days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.
The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.9. **Delay of Day-Ahead Energy Market Due to Mitigation Process.**
The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. **Physical and Financial Parameter Offer Thresholds.**
Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. **Time-Based Offer Parameters.**
Supply Offer parameters that are expressed in time (i.e., minimum run time, minimum down time, start time, and notification time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource’s Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. **Financial Offer Parameters.**
In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.
III.A.6.1.1. Other Offer Parameters.
Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource’s Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.


The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.
The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) The cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) The Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) The Lead Market Participant requests the cost-based Reference Level.
(d) During the previous 90 days:
   (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
   (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
   (iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.
ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO’s or the Internal Market Monitor’s systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource’s Supply Offers that have been accepted and are part of the seller’s Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource’s Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar days (weekday or weekend day), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 “Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources”.
(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

(i) Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

(ii) Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor’s determination of a Resource’s marginal costs shall include an assessment of the Resource’s incremental operating costs in accordance with the following formulas,

Incremental Energy:

\[(\text{incremental heat rate} \times \text{fuel costs}) + (\text{emissions rate} \times \text{emissions allowance price}) + \text{variable operating and maintenance costs} + \text{opportunity costs} \]

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits; and,
(c) other operating permits that limit production of energy.

No-Load:

\[(\text{no-load fuel use} \times \text{fuel costs}) + (\text{no-load emissions} \times \text{emission allowance price}) \]
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.


The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Capacity Scarcity Condition Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and Supply Offers made during the Re-Offer Period. A determination of non-competitiveness for a Day-Ahead Energy Market Supply Offer or a Supply Offer made during the Re-Offer Period which affects an hour shall constitute a finding of non-competitiveness for that hour.

(a) The thresholds used for evaluation shall be the general thresholds in Sections III.A.5.5.1 and III.A.5.5.3 unless the constrained area mitigation thresholds apply in the Day-Ahead Energy Market or Real-Time Energy Market and the resource under evaluation could have fully or partially relieved the constraint during the applicable Capacity Scarcity Condition Shortage Event. If the constrained area mitigation thresholds apply, then the energy price Supply Offer parameter and the Start-Up Fee and No-Load Fee parameters shall be evaluated for competitiveness using the thresholds in Sections III.A.5.5.2 and III.A.5.5.4.

(b) If the value of any of the following Supply Offer parameters for a resource exceeds the relevant thresholds for an hour, all MW for the resource for the hour shall be non-competitive:

(i) The Start-Up Fees and No-Load Fee;

(ii) Each time-based Supply Offer parameter;

(iii) The energy price Supply Offer parameter up to and including the Economic Minimum Limit.

(c) If none of the parameters evaluated for competitiveness pursuant to Section III.A.8 (b) above are non-competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the resource’s Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.8 (a) above, in order of lowest energy price to highest energy
price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.
The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: \( \frac{\text{LMP}_{\text{real time}}}{\text{LMP}_{\text{day ahead}}} - 1 \). The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant’s bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-
Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor’s authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor’s justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.
The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

\[(\text{LMP}_{\text{real time}} / \text{LMP}_{\text{day ahead}}) - 1\].

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.


The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.


If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the
number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR
Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five %
or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at
another Location is reflected in the constrained path between the subject FTR delivery and receipt
Locations that were acquired in the FTR Auction.


In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market
Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market.
Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor’s review
and the consequences that will result from the Internal Market Monitor’s determination following such
review.

(a) [Reserved].
(b) Section III.13.1.2.5.2 “Requirements for an Existing Generating Capacity Resource, Existing
Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified
Capacity than Winter Qualified Capacity.”
(c) Section III.13.1.2.3.2 “Review by Internal Market Monitor of Bids from Existing Generating
Capacity Resources.”
(d) Section III.13.1.3.5.6 “Review by Internal Market Monitor of Offers from New Import Capacity
Resources and Existing Import Capacity.”
(e) Section III.13.1.7 “Internal Market Monitor Review of Offers and Bids.”

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the
Forward Capacity Market.
Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As
addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a
reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The
Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The
Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner’s scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.
The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this Appendix A. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.
Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants’ obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer Appendix B in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.
Article 5 of the form of Cost-of-Service Agreement in Appendix I to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.


III.A.15.1. Filing Right.
If
(a) mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below,

and as a result of the action in (a) or (c), or despite the action in (b), the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.

III.A.15.1.1. Basis for declaration of an abnormal conditions alert.

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.
(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.

(c) A solar magnetic disturbance occurs.

(d) A cold weather event is declared.

(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.

(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.

(g) Operational staffing shortage impacting normal power system operations within New England occurs.

(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resources in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO has declared an abnormal conditions alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.
Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III A.15.

In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.


III.A.16.1. Actions Subject to Review.
A Market Participant may obtain prompt Alternative Dispute Resolution (“ADR”) review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in Appendix D to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.
On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market
Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor’s mitigation only if it concludes that the Internal Market Monitor’s application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor’s action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this Appendix A, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant’s cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;
(b) the accuracy of Demand Response Baselines;
(c) the method used to achieve a demand reduction, and;
(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.
The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market’s performance in the most recent period.

III.A.17.2.2. Quarterly Report.
The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this Appendix A.

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.
The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO’s website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this Appendix A.
III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.
The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO’s priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.
The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of Appendix A. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.
(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.
(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.
(iv) Review and assessment of the effectiveness of Appendix A and the administration of Appendix A by the Internal Market Monitor for consistency and compliance with the terms of Appendix A.

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;
(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil
investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as Exhibit 5.

III.A.18.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.
III.A.18.2.2. **Prohibition on Compensation for Services.**

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. **Additional Standards Applicable to External Market Monitor.**

In addition to the standards referenced in the remainder of this Section 18 of *Appendix A*, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. **Protocols on Referral to the Commission of Suspected Violations.**

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.
(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission’s Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

1. The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

2. The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

3. The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

4. The specific act(s) or conduct that allegedly constituted the Market Violation;

5. The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

6. If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission’s Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

7. Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.


(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and
recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission’s Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

1. A detailed narrative describing the perceived market design flaw(s);
2. The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;
3. The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;
4. Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.


The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1 Offer Review Trigger Prices.

For each new resource type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review
Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.


For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017) shall be as follows:

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustine Turbine</td>
<td>$10.00</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$11.00</td>
</tr>
<tr>
<td>Biomass</td>
<td>$24.00</td>
</tr>
<tr>
<td>On-Shore Wind</td>
<td>$14.00</td>
</tr>
<tr>
<td>Real-Time Demand Response</td>
<td>$1.00</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>$0.00</td>
</tr>
<tr>
<td>All Other Resource Types</td>
<td>Forward Capacity Auction Starting Price</td>
</tr>
</tbody>
</table>

Where a new resource is composed of assets having different resource types, the resource shall have an Offer Review Trigger Price equal to the highest of the applicable Offer Review Trigger Prices.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, the Offer Review Trigger Prices in the table above shall apply, based on the resource type of the External Resource. For any other New Import Capacity Resource, the Offer Review Trigger Price shall be $0.00/kW-month.

### III.A.21.1.2 Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the resource types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to develop the Offer Review Trigger Price is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting
model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model, rounded to the nearest whole dollar value. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

(c) For new energy efficiency resources, the methodology used to develop the Offer Review Trigger Price shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the programs’ life.

(d) For new Real-Time Demand Response resources, the methodology used to develop the Offer Review Trigger Price is based on an analysis of the incremental operating costs associated with the demand response business activities of selected industry firms engaged primarily in the demand response business, as reported in their Form 10k filings with the U.S. Securities and Exchange Commission. The Internal Market Monitor will review data regarding annual customer totals (MW) and operating costs (cost of sales), allocated marketing and sales expense, and allocated administrative and general expense for the three preceding consecutive years. The incremental MW and the total incremental operating costs for each firm is calculated and the incremental cost is then divided by the incremental MW to estimate the incremental revenues required to cover the cost of new Real-Time Demand Response MW. The Offer Review Trigger Price is set to the lowest calculated incremental revenue value for the selected firms during the studied years rounded to the nearest whole number.

III.A.21.2 New Resource Offer Floor Prices.
For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price, as described in this Section III.A.21.2.

(a) For a new capacity resource that does not submit a request to submit offers in the Forward
Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price applicable to the relevant resource type.

(b) For a new capacity resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.2.2.3 and III.13.1.4.2.4, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate.

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Real-Time Demand Response resource, the resource’s costs shall
include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response Provider to acquire the Real-Time Demand Response resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Real-Time Demand Response resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource’s qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project’s pro-forma financing support data. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource’s New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be equal to the requested offer price.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor’s capacity price estimate, then the resource’s New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price
estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource’s qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1.


For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource’s long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:
(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

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III.13.7.3.3.6   Specifically Allocated CTRs for Pool Planned Units.
III.13.7.3.4     Forward Capacity Market Net Charge Amount.

III.13.8     Reporting and Price Finality
III.13.8.1    Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.
III.13.8.2    Filing of Forward Capacity Auction Results and Challenges Thereto.
III.13.8.3    [Reserved.]
III.13.8.4    [Reserved.]
III.14       [Reserved.]

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.


To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.


A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted
as a capacity resource as described in Section III.13.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.2.

III.13.1.1.1. Resources Never Previously Counted as Capacity.
(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.2. Resources Previously Counted as Capacity.
A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section
III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource’s summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource’s summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:
(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than
2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the
Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified
Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii)
40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer
Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be
adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility
Construction Costs. These investment costs may include the costs associated with reactivating a resource
that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff
(or its predecessor provisions) and in which investment in the resource was undertaken prior to
reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction
as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the
megawatt amount approved in the resource’s Interconnection Agreement, the Project Sponsor must
submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of
Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental
amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity
Resource pursuant to this Section II.13.1.1.1.3 causes the resource to exceed the megawatt amount
approved in the resource’s Interconnection Agreement or MW amount approved pursuant to Section I.3.9
of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must
submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2 and a New Capacity
Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.
For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the
difference between the summer Qualified Capacity prior to the de-rating of the resource and the most
recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day
of October. The owner of a resource previously counted as a capacity resource that has been de-rated by
at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by
no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating
Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may
elect to have the incremental amount of capacity above the capacity level established while de-rated
treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.3 or Section III.13.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section
I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).


For a resource to qualify as a New Generating Capacity Resource, the resource’s Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.
III.13.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor’s contact information; the Project Sponsor’s ISO customer status; the project’s expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification
process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package.
between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.2.8.

III.13.1.2.2.1. Site Control.
For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.2.2.2. Critical Path Schedule.
In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.
(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels; (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.
(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. **Offer Information.**

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity 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 the OATT.

III.13.1.1.2.2.4. **Capacity Commitment Period Election.**

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer
clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.2.2.4.

III.13.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (re-powering), Section III.13.1.1.3 (incremental capacity), or Section III.13.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.2(b), III.13.1.1.3(b), and III.13.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, or III.13.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.2.2.2.

III.13.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.
(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form cannot be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource’s Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form cannot be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource cannot provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form cannot be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.
(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.2.4. Evaluation of New Capacity Qualification Package.
The ISO shall review a New Generating Capacity Resource’s New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:
(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource’s claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a 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.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section
III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource’s summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. **New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.**

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. **[Reserved.]**

III.13.1.1.2.7. **Opportunity to Consult with Project Sponsor.**

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor 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 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 believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor 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.
### III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource’s New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource’s summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating
Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.2.2.3, the Internal Market Monitor’s determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.
An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.
The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal
Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.
The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource’s net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource’s or Intermittent Settlement Only Resource’s summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.1(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to
the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

**III.13.1.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.**

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource’s and Intermittent Settlement Only Resource’s winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

**III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.**

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification
process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer
Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource’s summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, 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 Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.3(a) but not the requirements of Section III.13.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource’s summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of
incremental capacity as described in Section III.13.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.5.1. [Reserved.]

III.13.1.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource’s summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.
For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource’s Lead Market Participant of the resource’s summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single
resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation out of the capacity market at prices at or above the Dynamic De-List Bid Threshold$1.00/kW-month during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the
ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.2.1.2. Permanent De-List Bids.
An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource’s full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.
An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing
Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.
A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.
The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.
The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request
will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. **Obligation to Retire.**

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. **Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.**

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. **Submission of Cost Data.**

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist 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.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. **Internal Market Monitor Review.**

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing 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 de-list 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 de-listing of each individual asset in preferred de-list 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 bids 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 bids 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 Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if: (1) at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:
(a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold$1.00/kW-month, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold$1.00/kW-month.
The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold $1.00/kW-month, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource’s net risk-adjusted going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.24); (2) reasonable expectations about the resource’s Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource’s reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.52). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, and 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 resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

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 qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, 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.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.
(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and 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. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the
resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW-month.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect
to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW-month.

(b)(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1. A Lead Market Participant making such an election shall
be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW-month.

III.13.1.2.3.2.1.2. Net Risk-Adjusted Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold $1.00/kW-month, or Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month shall be considered consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

\[
\frac{\left[ GFC - (IMR - PER) \right] \times \text{InflIndex}}{(CQ_{\text{Summer}}, \text{kw}) \times (12, \text{months})}
\]

\[
\frac{\left[ GFC \div (44) \right] + \left[ RF \right] = \left[ (IMR = PER) \right] \times \text{InflIndex}}{(CQ_{\text{Summer}}, \text{kw}) \times (42, \text{months})}
\]

Where:

GFC = annual going forward costs, in dollars. These are costs 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 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 Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

\[ C_{\text{Summer}, \text{kW}} = \text{capacity seeking to de-list in kW}. \text{ In no case shall this value exceed the resource’s summer Qualified Capacity.} \]

\[ RF = \text{risk factor, in dollars. This value shall be calculated using the following formula:} \]

\[ RF = \left( \frac{\text{RPC} \times EFORd}{(P \times (\text{Forward Capacity Auction Starting Price} - AFCAP) \times 12, \text{months})} \right) \times C_{\text{Summer}, \text{kW}} \]

Provided: If \( EFORd \) is greater than 0.40 then 0.40 shall be used, and if \( EFORd \) is less than 0.05 then 0.05 shall be used.

\( EFORd \) shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.
RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit’s daily price to the resource’s Real-Time nodal price. For each hour that the resource’s nodal price exceeds the PER Proxy Unit’s daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit’s daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.

P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource’s Capacity Zone.

AA = availability adjustment. AA = (1 – EFORd)

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual 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 Existing Generating Capacity Resource’s total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource’s total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.

\[ \text{InfIndex} = \text{inflation index} = (1 + i)^4 \]

Where: “\(i\)” is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

**III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.**

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource’s performance during reserve deficiencies.

**III.13.1.2.3.2.1.4. Risk Premium.**
The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, 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.13.1.2.3.2.1.2 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 Forward Capacity Market is consistent with the participant’s corporate risk management practices.

III.13.1.2.3.2.1.53. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold $1.00/kW-month, or Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, 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. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).
III.13.1.2.3.2.2.  [Reserved.]

III.13.1.2.3.2.3.  Administrative Export De-List Bids.
The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4.  Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.
A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5.  Incremental Capital Expenditure Recovery Schedule.
Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

<table>
<thead>
<tr>
<th>Age of Existing Resource (years)</th>
<th>Remaining Life (years)</th>
<th>Annual Rate of Capital Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 to 5</td>
<td>30</td>
<td>0.106</td>
</tr>
<tr>
<td>6 to 10</td>
<td>25</td>
<td>0.110</td>
</tr>
</tbody>
</table>
A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1-(1+\text{Cost Of Capital})^{-\text{Remaining Life}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

### III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2,
the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:
III.13.1.3.1. **Definition of Existing Import Capacity Resource.**

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. **Qualified Capacity for Existing Import Capacity Resources.**

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. **Qualification Process for Existing Import Capacity Resources.**
Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

<table>
<thead>
<tr>
<th>Contract Description</th>
<th>MW</th>
<th>Contract End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYPA: NY—NE: CMEEC</td>
<td>13.2</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY—NE: MMWEC</td>
<td>53.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY—NE: Pascoag</td>
<td>2.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY—NE: VELCO</td>
<td>15.3</td>
<td>8/31/2025</td>
</tr>
</tbody>
</table>
III.13.1.3.4. **Definition of New Import Capacity Resource.**

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. **Qualification Process for New Import Capacity Resources.**

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. **Documentation of Import.**

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area (beginning 11/01/2016).
Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New 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 (iv) documentation for system-backed import capacity that the import capacity 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. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England’s import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the 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 New Import Capacity Resource’s potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the
external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.
The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification 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. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.
The provisions regarding Capacity Commitment Period election (Section III.13.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.
The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. **Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.**

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. **Qualification Determination Notification for New Import Capacity Resources.**

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. **Rationing Election.**

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. **Demand Resources.**

III.13.1.4.1. **Demand Resources.**

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to
participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with
the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity
offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A
Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration
auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life.
Demand 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 Resource. Demand Resources are not permitted to submit import or export bids
or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its
Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market
Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.
Demand Resources that previously have been in service and registered with the ISO, and which are not
otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources
shall include and are limited to (i) Demand Resources that have been in service and registered with the
ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii)
Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour)
and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before
the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as
specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification
process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand
Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-
Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that
Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets
associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources
may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response
Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.
A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.
For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource’s Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources
For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.
III.13.1.4.1.3. **Special Provisions for Real-Time Emergency Generation Resources.**

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. **Show of Interest Form for New Demand Resources.**

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource
Project Sponsor’s capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package
shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1.  [Reserved.]

III.13.1.4.2.2.  Source of Funding.
The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3.  Measurement and Verification Plan.
For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4.  Customer Acquisition Plan.
A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1.  Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.
For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.
III.13.1.4.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete.

III.13.1.4.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor’s ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor’s program to deliver capacity to meet the Demand Resource Project Sponsor’s Forward Capacity Auction obligations, and must include each customer’s projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor’s ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity...
Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO’s critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. **Capacity Commitment Period Election.**

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. **Rationing Election.**

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. **Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.**
The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource’s Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO’s notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if
applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. **Notification of Qualification for New Demand Resources.**

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. **Notification of Acceptance to Qualify of a New Demand Resource.**

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource’s summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. **Notification of Failure to Qualify of a New Demand Resource.**

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. **Measurement and Verification Applicable to All Demand Resources.**

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated
with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. 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.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. **Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.**

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project’s Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource’s Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor’s total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor’s total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as
of the end of the previous month. The monthly Measurement and Verification Summary Reports 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 Demand Resource Project Sponsors. 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.

III.13.1.4.3.1.1. **Optional Measurement and Verification Reference Reports.**
At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. **Updated Measurement and Verification Documents.**
At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor’s offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. **Annual Certification of Accuracy of Measurement and Verification Documents.**
Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue 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 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.
For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors 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 Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor 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 Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.
The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation,
Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.
Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the
simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.
The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.
Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.
The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.
III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.


A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the
resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.


A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at 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 and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7.   [Reserved.]

III.13.1.4.8.   [Reserved.]


A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers’ demand response to be bid into the ISO-administered markets or programs, or
(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers’ demand response to be bid into the ISO-administered markets or programs.


A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer’s demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.


If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer’s facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO’s asset registration system, to which the end-use customer’s facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource’s highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity
Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource’s highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.
Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) 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 (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity
Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources 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.13.1.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources 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) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource’s final FCA
Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource’s financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. **Self-Supplied FCA Resources.**
Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity’s share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. **Self-Supplied FCA Resource Eligibility.**
Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity’s projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity’s most
recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource’s summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.
In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource’s summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.
(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold$1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.


Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource’s financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.


Where a New Generating Capacity Resource’s offer or a New Demand Resource’s offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, 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 an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand 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 resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]


Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.


A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.


For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost
Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual 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. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under
Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

<table>
<thead>
<tr>
<th>New Generating Resources ≥ 20 MW</th>
<th>New Generating Resources &lt; 20 MW and ≥ 2 MW</th>
<th>Imports and New Demand Resources (including Distributed Generation)</th>
<th>New Generating Resources &lt; 2 MW</th>
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</thead>
<tbody>
<tr>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td></td>
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<tr>
<td>$25,000</td>
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<td>$1,000</td>
<td>$500</td>
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<tr>
<td>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</td>
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<td>$15,000</td>
<td>$6,500</td>
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**III.13.1.9.3.2. Settlement of Costs.**

**III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.**

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor 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. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds 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, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If 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 exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in
accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO’s consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.


The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.
<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
</table>
Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feb. (X-4)</td>
<td>June (X-4)</td>
<td>June/July (X-4)</td>
<td>Feb. (X-3)</td>
<td>June X</td>
</tr>
</tbody>
</table>

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3.  Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2.  Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a)  Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

(i)  The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic
Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be \( P_S \) and \( P_E \), respectively. Let the \( m \) prices \( (1 \leq m \leq 5) \) submitted by a Project Sponsor for a modeled Capacity Zone be \( p_1, p_2, ..., p_m \), where \( P_S > p_1 > p_2 > ... > p_m \geq P_E \), and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be \( q_1, q_2, ..., q_m \). Then the Project Sponsor’s supply curve, for all prices strictly less than \( P_S \) but greater than or equal to \( P_E \), shall be taken to be:

\[
S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
& \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}
\]

where, in the first round, \( q_0 \) is the resource’s full FCA Qualified Capacity and, in subsequent rounds, \( q_0 \) is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-
List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold $1.00/kW-month (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in
Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round’s relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) Repowering. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource
pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.
III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the “Total System Capacity”) shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) Import-Constrained Capacity Zones.

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

1. the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone’s Local Sourcing Requirement; or
(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.** For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:
(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone’s Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):
(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is
connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

**III.13.2.3.4. Determination of Final Capacity Zones.**

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.
(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).
The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.
Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.
Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.
A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.
An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.
III.13.2.5.2.5. **Bids Rejected for Reliability Reasons.**

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity); or (iii) as
soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability
reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, 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. For de-list bids, this review and update will follow ISO’s filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.
(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods
following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.
(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. **Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:**

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ISO New**
England: A resource seeking to avail itself of the recovery mechanism provided in this Section 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, 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 III.13.2.5.2.5.1(c), 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.

### III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity
Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved
Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing
Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).
(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II
HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone’s Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.2.2.6 and Section III.13.1.2.2.2.
III.13.2.7.7. **Tie-Breaking Rules.**

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8.  **[Reserved.]**

III.13.2.7.9 **Capacity Carry Forward Rule.**

III.13.2.7.9.1. **Trigger.**

The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and
(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.
An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local...
Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone’s Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.
(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.
The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.4.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.
(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

   (i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

   (ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

   (iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section, III.13.2.8.2, a Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating
Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]
III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

   (i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

   (ii) the transmission interface limits as determined pursuant to Section III.12.5;

   (iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

   (iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward 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;

   (v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

   (vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

   (vii) the Internal Market Monitor’s determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including
information regarding each of the elements considered in the Internal Market Monitor’s
determination of expected net revenues (other than revenues from ISO-administered markets) and
whether that element was included or excluded in the determination of whether the offer is
consistent with the resource’s long run average costs net of expected net revenues other than
capacity revenues;

(viii) the Internal Market Monitor’s determinations regarding offers or bids submitted during
the qualification process made according to the provisions of this Section III.13, including an
explanation of the reasons for rejecting any de-list bids from resources associated with pivotal
Lead Market Participants as described in Section III.13.1.2.3.2 based on the Internal Market
Monitor review and the resource’s net going forward costs, reasonable expectations about the
resource’s Capacity Performance Payments, reasonable risk premium assumptions, and
reasonable opportunity costs net risk-adjusted going forward costs and opportunity costs as
determined by the Internal Market Monitor. The filing shall identify to the extent possible the
components of the bid which were accepted as justified, and shall also identify to the extent
possible the components of the bid which were not justified and which resulted in rejection of the
bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction
(this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity
Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described
in Section III.13.8.1(a) or in the qualification determination notifications described in Sections
III.13.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section
III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO’s submission
of the informational filing. If the Commission does not issue an order within 75 days after the ISO’s
submission of the informational filing that directs otherwise, the determinations contained in the
informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting
the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward
Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within

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75 days after the ISO’s submission of the informational filing, the Commission does issue an order modifying one or more of the ISO’s determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO’s filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.
(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3.  [Reserved.]

III.13.8.4.  [Reserved.]
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Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.2.2.4.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted
as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:
(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource’s summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource’s summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified
Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource’s Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.3 causes the resource to exceed the megawatt amount approved in the resource’s Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.4. **De-rated Capacity of Resources Previously Counted as Capacity.**

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form
pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.3 or Section III.13.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

For a resource to qualify as a New Generating Capacity Resource, the resource’s Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.
Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity
Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website. A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor’s contact information; the Project Sponsor’s ISO customer status; the project’s expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.2.2.
(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.
For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has
already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option, exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control
systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

**III.13.1.2.2.3. Offer Information.**

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward
Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity 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 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.
In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.
In addition to the information described elsewhere in this Section III.13.1.1.2.2:
(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance
data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource’s Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating
Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as
described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource’s New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource’s claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.
III.13.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a 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.

III.13.1.2.5.2. [Reserved]

III.13.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource’s summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating
Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6.  [Reserved.]

III.13.1.1.2.7.  Opportunity to Consult with Project Sponsor.
In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor 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 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 believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor 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.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource’s New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct
those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource’s summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor’s determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.
An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.
### III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

#### III.13.1.2.2.1.1. Summer Qualified Capacity.
The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

#### III.13.1.2.2.1.2. Winter Qualified Capacity.
The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation.
Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource’s net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).
(b) The Intermittent Power Resource’s or Intermittent Settlement Only Resource’s summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) 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 the ISO has declared there was a system-wide Capacity Scarcity Condition Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource’s and Intermittent Settlement Only Resource’s winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 the ISO has declared there was a system-wide Capacity Scarcity Condition Shortage Event and if the Intermittent Power Resource or
Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all **Capacity Scarcity Conditions** in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

**III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.**

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner
consistent with Section III.13.1.2.1.2] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s winter Qualified Capacity shall be calculated as described in Section III.13.1.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource’s summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, 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 Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity
Commitment Period; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.
Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource’s summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.
Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource’s summer Qualified
Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

### III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource’s Lead Market Participant of the resource’s summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.1.2.3.2(c).

#### III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or
withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

**III.13.1.2.3.1.A Dynamic De-List Bid Threshold.**

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.
III.13.1.2.3.1.1. **Static De-List Bids.**

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. **Permanent De-List Bids.**

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource’s full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy
and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Unless
reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.
A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.
The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.
The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4.  Obligation to Retire.
A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6.  Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.
Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1.  Submission of Cost Data.
In addition to the information required elsewhere in this Section III.13.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist 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.

III.13.1.2.3.1.6.2.  [Reserved.]

III.13.1.2.3.1.6.3.  Internal Market Monitor Review.
The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing 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 de-list 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 de-listing of each individual asset in preferred de-list 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 bids 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 bids 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 Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if: (1) at the Forward Capacity Auction Starting Price, the total
amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.
The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource’s net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource’s Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource’s reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the 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 resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.
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 qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, 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.

III.13.1.2.3.2.1.1. Review of Permanent De-List Bids and Export Bids.
(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).
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Attachment A

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and 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. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.
(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.
(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and 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. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than 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 and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net going forward costs, reasonable expectations about the resource’s Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

III.13.1.2.3.2.1.2. Net Going Forward Costs.
The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the
Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net
going forward costs using ISO spreadsheets and forms provided, and may supplement this information
with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List
Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered
consistent with the Existing Generating Capacity Resource’s net going forward costs based on a review of
the data submitted in the following formula. To the extent possible, all costs and operational data used in
this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from
the most recent full Capacity Commitment Period available.

\[
\left[ \frac{GFC - (IMR - PER)}{(CQ_{\text{Summer}}, \text{kw}) \times (12, \text{months})} \right] \times \text{InflIndex}
\]

Where:

GFC = annual going forward costs, in dollars. These are costs 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 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 Static De-List Bid or Permanent De-List Bid that the resource will not be
participating in the energy and ancillary services markets during the Capacity Commitment Period (and
thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the
spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a
Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and
shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data
used to calculate these data do not reflect known and measurable costs that would or are likely to be
incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider
adjustments submitted, provided the costs are based on known and measurable conditions and supported
by appropriate documentation to reflect those costs.
CQ$_{\text{Summer}}$ kW = capacity seeking to de-list in kW. In no case shall this value exceed the resource’s summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual 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 Existing Generating Capacity Resource’s total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource’s total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.

InfIndex = inflation index. infIndex = (1 + i)^4

Where: “i” is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.
The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource’s performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, 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.13.1.2.3.2.1.2 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 Forward Capacity Market is consistent with the participant’s corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, 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.13.1.2.3.2.2.  [Reserved.]

III.13.1.2.3.2.3.  Administrative Export De-List Bids.
The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4.  Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.
A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5.  Incremental Capital Expenditure Recovery Schedule.
Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

<table>
<thead>
<tr>
<th>Age of Existing Resource (years)</th>
<th>Remaining Life (years)</th>
<th>Annual Rate of Capital Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 to 5</td>
<td>30</td>
<td>0.106</td>
</tr>
<tr>
<td>6 to 10</td>
<td>25</td>
<td>0.110</td>
</tr>
<tr>
<td>11 to 15</td>
<td>20</td>
<td>0.117</td>
</tr>
</tbody>
</table>
A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

\[
\text{Cost Of Capital} \left(1 - \frac{1}{1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}}}ight)
\]

Where:
Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

**III.13.1.2.4. Qualification Determination Notification for Existing Capacity.**

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.
III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

<table>
<thead>
<tr>
<th>External Node Common Name</th>
<th>Capacity Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>NB-NE External Node</td>
<td>Maine</td>
</tr>
<tr>
<td>HQ Phase I/II External Node</td>
<td>Rest-of-Pool</td>
</tr>
</tbody>
</table>
III.13.1.3.1. **Definition of Existing Import Capacity Resource.**

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. **Qualified Capacity for Existing Import Capacity Resources.**

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. **Qualification Process for Existing Import Capacity Resources.**

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a
period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

<table>
<thead>
<tr>
<th>Contract Description</th>
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<td>Up to 110</td>
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III.13.1.3.4. Definition of New Import Capacity Resource.
Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New 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 (iv) documentation for system-backed import capacity that the import capacity 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. For each New Import Capacity Resource, the Market Participant must
specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England’s import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.
If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the 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 New Import Capacity Resource’s potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.
If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.
The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. 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 Market Participant entering the import
contract shall demonstrate, as detailed in the ISO New England Manuals, 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification 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. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.
The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.
The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.
In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the
protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand 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 Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.
A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

### III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

### III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.2.

### III.13.1.4.1.3. Demand Reduction Values.
A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Sections III.13.1.4.1.3.1, III.13.1.4.1.3.2, III.13.1.4.1.3.3 and III.13.1.4.1.3.4.

**III.13.1.4.1.3.1 Calculation of Demand Reduction Values for On-Peak Demand Resources.**

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

**III.13.1.4.1.3.1.1 Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

**III.13.1.4.1.3.1.2 Winter Seasonal Demand Reduction Value.**

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

**III.13.1.4.1.3.2 Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.**

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.
III.13.1.4.1.3.2.1. **Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.1.4.1.3.2.2. **Winter Seasonal Demand Reduction Value.**

The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.1.4.1.3.3. **Demand Reduction Values for Real-Time Demand Response Resources.**

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.1.4.1.3.3.1. **Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand
Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.1.4.1.3.3, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.1.4.1.3.3.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.1.4.1.3.3, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.1.4.1.3.3.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.1.4.1.3.3.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.
An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the
Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.1.4.1.3.4. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours.
Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.1.4.1.3.4.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.1.4.1.3.4, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.1.4.1.3.4.2. **Winter Seasonal Demand Reduction Value.**
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.1.4.1.3.4 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.1.4.1.3.4.3. **Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.**
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation
and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

**III.13.1.4.1.3.4.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.**

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.

**III.13.1.4.1.42.1. Qualified Capacity of New Demand Resources.**

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource’s Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.
The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.52.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.


All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2
shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or
greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. **Qualification Package for Existing Demand Resources.**
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. **Qualification Package for New Demand Resources.**
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. **Source of Funding.**
The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. **Measurement and Verification Plan.**
For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. **Customer Acquisition Plan.**
A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete.

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second
Critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor’s ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor’s program to deliver capacity to meet the Demand Resource Project Sponsor’s Forward Capacity Auction obligations, and must include each customer’s projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor’s ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO’s critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods.
for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.5.

III.13.1.4.2.6. Rationing Election.
The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.
The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.
All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.
III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.
The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.
For each Existing Demand Resource, the ISO will notify the Resource’s Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of
the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO’s notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.
No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.
For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource’s summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.
For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.
To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project
Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. 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.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project’s Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource’s Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification
Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor’s total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor’s total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports 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 Demand Resource Project Sponsors. 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.

### III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

### III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor’s offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in
the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. **Annual Certification of Accuracy of Measurement and Verification Documents.**

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue 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 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. **Record Requirement of Retail Customers Served.**

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors 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 Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor 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 Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. **Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.**

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity
Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

### III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.
Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.
The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.
Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.
The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. **Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.**

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. **Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.**

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. **Selection of Active Demand Resources For Dispatch.**

III.13.1.4.5.1. **Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.**

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report
to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.


A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at 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 and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.3. **Capacity Values of Demand Resources.**

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.1.4.1.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.1.4.6.2.4 **Capacity Values of Certain Distributed Generation.**

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset’s monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output
exceeding the customer’s load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]


A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers’ demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers’ demand response to be bid into the ISO-administered markets or programs.


A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail regulatory authority prohibits such customer’s demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.
If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer’s facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO’s asset registration system, to which the end-use customer’s facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.
The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource’s highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource’s highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.
Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:
(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) 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 (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources 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.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources 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) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.
(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.
No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource’s final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource’s financial assurance requirements in accordance with Section III.13.1.9.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity’s share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.


Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity’s projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity’s most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource’s summer Qualified Capacity and winter Qualified Capacity.

### III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.


In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource’s summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission.
in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

**III.13.1.8. Publication of Offer and Bid Information.**

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.2.8,
III.13.1.9. **Financial Assurance.**

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.


In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource’s financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

Where a New Generating Capacity Resource’s offer or a New Demand Resource’s offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. **Failure to Provide Financial Assurance or to Meet Milestone.**

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. **Release of Financial Assurance.**

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, 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 an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand 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 resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. **Forfeit of Financial Assurance.**

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. **Financial Assurance for New Import Capacity Resources.**

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation,
the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. **Qualification Process Cost Reimbursement Deposit.**

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual 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. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued...
coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

<table>
<thead>
<tr>
<th>New Generating Resources ≥ 20 MW</th>
<th>New Generating Resources &lt; 20 MW and ≥ 2 MW</th>
<th>Imports and New Demand Resources (including Distributed Generation)</th>
<th>New Generating Resources &lt; 2 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td>$25,000</td>
<td>$7,500</td>
</tr>
<tr>
<td>$25,000</td>
<td>$7,500</td>
<td>$1,000</td>
<td>$500</td>
</tr>
<tr>
<td>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</td>
<td>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</td>
<td>$15,000</td>
<td>$6500</td>
</tr>
<tr>
<td>$15,000</td>
<td>$6500</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor 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. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds 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, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If 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 exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO’s consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.
<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
</table>
Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feb. (X-4)</td>
<td>June (X-4)</td>
<td>June/July (X-4)</td>
<td>Feb. (X-3)</td>
<td>June X</td>
</tr>
</tbody>
</table>

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price
associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.
The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.
(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be \( P_S \) and \( P_E \), respectively. Let the \( m \) prices (\( 1 \leq m \leq 5 \)) submitted by a Project Sponsor for a modeled Capacity Zone be \( p_1, p_2, \ldots, p_m \), where \( P_S > p_1 > p_2 > \ldots > p_m \geq P_E \), and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be \( q_1, q_2, \ldots, q_m \). Then the Project Sponsor’s supply curve, for all prices strictly less than \( P_S \) but greater than or equal to \( P_E \), shall be taken to be:

\[
S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\vdots & \vdots \\
q_m, & \text{if } p \leq p_m. 
\end{cases}
\]

where, in the first round, \( q_0 \) is the resource’s full FCA Qualified Capacity and, in subsequent rounds, \( q_0 \) is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of
that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round’s relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner...
as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) Repowering. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.
(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

**III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.** The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the “Total System Capacity”) shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones
modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

1. the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone’s Local Sourcing Requirement; or

2. the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two
conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.** For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone’s Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);
then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources
and Existing Import Capacity Resources over the interface; and the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(c) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient
Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.
III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.
Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.
A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.
An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.
The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but
the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that its bid did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.
(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, 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. For de-list bids, this review and update will follow
ISO’s filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. **Compensation for Bids Rejected for Reliability Reasons.**

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. 
Resources that elect payment based on the accepted Permanent De-List Bid may file with the 
Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the 
unit is retained for reliability for a period longer than the Capacity Commitment Period for which the 
Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified 
the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year 
preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid 
was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity 
Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid 
was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods 
following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment 
pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the 
ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been 
submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and 
the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue 
to be paid in the same manner as other listed capacity resources until such time as the resource is no 
longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has 
been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 
and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect 
to either (i) continue to be paid in the same manner as other listed capacity resources until such time as 
the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service 
compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within 
six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. 
A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not 
notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed 
capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).
III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:
In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ISO New England: A resource seeking to avail itself of the recovery mechanism provided in this Section 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, 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 III.13.2.5.2.5.1(c), 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.

III.13.2.5.2.5.3. Retirement of Resources
(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.
(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]
III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).


Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.
The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. **Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.**

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. **Capacity Clearing Price Floor.**

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.
(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.
At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that
price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. **Effect of Capacity Rationing Rule on Capacity Clearing Price.**

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone’s Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. **Effect of Decremental Repowerings on the Capacity Clearing Price.**

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.
III.13.2.7.6. **Minimum Capacity Award.**

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. **Tie-Breaking Rules.**

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 **Capacity Carry Forward Rule.**

III.13.2.7.9.1. **Trigger.**
The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.
III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone’s Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).
(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the
Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

   (i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

   (ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or
(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section III.13.2.8.2, a Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]
III.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), or a New Demand Resource (pursuant to Section III.13.1.4), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource’s compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 from the time that the Forward Capacity Auction is conducted until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.2. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource’s compliance with its critical path schedule after the Forward Capacity Auction unless, within 5 Business Days after the Forward Capacity Auction is completed, the Project Sponsor for that resource requests in writing that the ISO continue to monitor that resource’s compliance with its critical path schedule. A New Generating Capacity Resource may not, however, request that the ISO continue to monitor that resource’s compliance with its critical path schedule pursuant to this Section III.13.3.1.2 if that resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Generating Capacity Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Generating Capacity Resource.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor 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 Project Sponsor 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 Project Sponsor. If the Project Sponsor 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.13.3.4(c). Each critical path schedule report shall include the following:

### III.13.3.2.1. 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.13.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor 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 Project Sponsor should 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.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW (discussed in Section III.13.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 component, subsequent Commercial Operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation 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 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.** If during the qualification process it was determined that, because of overlapping interconnection impacts, transmission upgrades are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Resource projects installed at multiple facilities and Demand Resource projects 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 Project Sponsor 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 Project Sponsor shall provide documentation showing the total offered Demand Reduction Value achieved as of target dates which are: (a) the cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource supplier’s capacity award was made; (b) the cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource supplier’s capacity award was made; and (c) target date 3 which is the date the resource is expected to achieve commercial operation, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total Demand Reduction Value must be complete.

(ii) **Pipeline Analysis.** If the Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then the Project Sponsor shall provide a pipeline analysis to the ISO as specified in Section III.13.1.4.2.2.4.3 of Market Rule 1.

(iii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor 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 Project Sponsor shall also provide the asset identification number.

III.13.3.2.3. Additional Relevant Information.
The Project Sponsor 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 or the feasibility that the project will meet the requirement that the project achieve Commercial Operation no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.
For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4 or New Demand Resource pursuant to Section III.13.1.4.1.2 and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource’s Capacity Supply Obligation in accordance with the provisions of Section III.13.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.2, III.13.1.1.3, and III.13.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.
If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor 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 including Commercial Operation of the project. If a milestone date is revised for any reason, the ISO may require the Project Sponsor 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 Project Sponsor 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 Project Sponsor. If the Project Sponsor 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.13.3.4(c). Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.
III.13.3.4. **Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.**

If as a result of milestone date revisions made pursuant to Section III.13.3.3, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except for a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation in the circumstances described in Section III.13.7.1.1.3(h) and Section III.13.7.1.1.3(i)), then the Project Sponsor must take actions to cover the entire Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, as follows:

(a) The Project Sponsor may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4 or one or more Capacity Supply Obligation Bilaterals, which must be submitted to the ISO as described in Section III.13.5.

(b) If, by the time demand bids are due for the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, the Project Sponsor has not covered its full Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, then the ISO shall submit a demand bid in that annual reconfiguration auction on the Project Sponsor’s behalf for a quantity equal to the largest monthly Capacity Supply Obligation for the Capacity Commitment Period that has not been covered, at the Forward Capacity Auction Starting Price (with all payments, charges, rights, obligations, and other results associated with such demand bid applying to the Project Sponsor as if the Project Sponsor itself had submitted the demand bid).

(c) If the Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if the Capacity Supply Obligation is not covered as described in Sections III.13.3.4(a) and III.13.3.4(b), or if the Project Sponsor covers the Capacity Supply Obligation for two Capacity Commitment Periods, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource’s Capacity Supply Obligation for any future Capacity Commitment Periods and the resource’s right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource’s qualified capacity for participation in the Forward Capacity Market. Upon Commission ruling, the Project Sponsor 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’s Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO’s right to revoke that permission and to file with the Commission to terminate the resource’s Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

III.13.3.5. Termination of Interconnection Agreement.
If the ISO files with the Commission to terminate a resource’s Capacity Supply Obligation as described in Section III.13.3.4(c), the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4.
Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.
A resource having a Capacity Supply Obligation seeking to shed that obligation (“Capacity Transferring Resource”) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (“Capacity Supply Obligation Bilateral”), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (“Capacity Acquiring Resource”), subject to the following limitations

(a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.
(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) The Capacity Transferring Resource and the Capacity Acquiring Resource that are parties to a Capacity Supply Obligation Bilateral must be located in the same Capacity Zone, or the path from the Capacity Transferring Resource to the Capacity Acquiring Resource must flow across adjacent Capacity Zones in the direction of the modeled interface constraint(s), as such Capacity Zones and interface constraints are defined following the Forward Capacity Auction conducted for the Capacity Commitment Period to which the transferred Capacity Supply Obligation applies.

(g) If the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA 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 FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.
III.13.5.1.1.1. **Timing of Submission.**
The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO before or during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating Procedures. The ISO will issue a schedule of the submittal windows for annual and monthly Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. 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.13.5.1.1.2. **Application.**
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, 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.13.5.1.1.3. **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 provisions of this Section III.13.5.1 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 relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO’s review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity
Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO’s reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource. The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting 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.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.
A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). 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.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.
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 settlement of payments and charges associated with the Forward 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 pm on the second Business Day after the end 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.13.5.2.1.2. Application.
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.13.5.2.1.3. 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 II.13.5.2 are not met.

III.13.5.2.1.4. 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 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.

III.13.5.3. Supplemental Availability Capacity Performance Bilaterals.
A resource’s Capacity Performance Score availability score during a Capacity Scarcity Condition Shortage Event may be adjusted supplemented by entering into a Supplemental Availability Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1. Eligibility.
If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition. Demand Response Capacity Resources and Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource or reduced by the resource’s capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented) and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. A Demand Response Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource’s Qualified Capacity from the Forward Capacity Auction for the
current Capacity Commitment Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

### III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource’s Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

### III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

### III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources and as described in Sections III.13.6.1.5.1. and III.13.6.1.5.2. for Demand Response Capacity Resources for the entire term indicated in the designation described in Section III.13.5.3.1.2.

### III.13.5.3.2. Submission of Supplemental Availability Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score available capability up to its designated supplemental capacity in each hour of that
Shortage Event to a Generating Capacity Resource or Demand Response Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.
A Supplemental Availability Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Capacity Performance Bilateral, a Supplemental Availability Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.
The submission of a Supplemental Availability Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score Supplemental Capacity Resource; (ii) the resource identification number for the resource receiving the Capacity Performance Score Supplemented Capacity Resource; (iii) the MW amount of Capacity Performance Score capacity being transferred assigned from the Supplemental.
Capacity Resource to the Supplemented Capacity Resource; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.
The ISO shall review the information provided in submission of the Supplemental Availability Capacity Performance Bilateral, and shall reject the Supplemental Availability Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is (a) less than or equal to the difference between the Generating Capacity Resource’s Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource’s Capacity Supply Obligation or (b) less than or equal to the difference between (the greater of the Demand Response Capacity Resource’s Real-Time Demand Reduction Obligation plus Net Supply or the lesser of ((the Demand Response Capacity Resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5, plus the Economic Maximum Limit for any associated available Net Supply Generator Assets), the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared by the Lead Market Participant plus the Economic Maximum Limit of associated Net Supply Generator Assets))), adjusted for average avoided peak transmission and distribution losses as addressed in Section III.13.7.1.5.10, and the Supplemental Capacity Resource’s Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource’s Real-Time Reserve Designations of TMNSR and TMOR and the Supplemental Capacity Resource’s Capacity Supply Obligation.

III.13.5.3.32.4. Effect of Supplemental Availability Capacity Performance Bilateral.
A Supplemental Availability Capacity Performance Bilateral does not affect in any way either party’s Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2 Supplemented Capacity Resource’s availability score as described in Section III.13.7.1.4.
III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.


AGenerating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource’s notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) 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

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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.3. [Reserved.]

III.13.6.1.4. [Reserved.]

III.13.6.1.5. 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;

(c) 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 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.13.6.1.2.    Import Capacity Resources.


The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of
the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1.1(b)(iii) and the lower of ultra-low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra-low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.


(bd) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(ce) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2.

III.13.6.1.2.2. Additional Requirements for Certain Import Capacity Resources.

The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the
enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory rescheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.

Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with the requirements in this Section III.13.6.1.2.3 may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

(a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.
(b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.

(c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.

(d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers 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.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.
III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.


III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.
Intermittent Settlement Only Resources and Non-Intermittent Settlement Only 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;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

A Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers through its Demand Response Resources and submit Supply Offers of any associated Net Supply Generator Assets, into both the Day-Ahead Energy Market and Real-Time Energy Market through its Demand Response Resources and associated Net Supply Generator Assets. The sum of the Demand Reduction Offers and Supply Offers must be equal to or greater than the Demand Response Capacity Resource’s Capacity Supply Obligation whenever the Demand Response Resources and associated Net Supply Generator Assets are physically available. If the Net Supply Generator Asset is a
Settlement Only Resource, then the Net Supply will not be represented in the offer for the Demand Response Resource. If the Demand Response Resources and associated Net Supply Generator Assets are physically available at a level less than the Demand Response Capacity Resource’s Capacity Supply Obligation, the sum of the Demand Reduction Offers and Supply Offers equal to that level 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 one of the following requirements:

(a) 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) the sum of the Demand Response Resource’s Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

Each Supply Offer for a Net Supply Generator Asset associated with a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:

(a) the sum of the Net Supply Generator Asset’s Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours.

(b) the sum of the Net Supply Generator Asset’s Minimum Run Time plus Minimum Down Time is less than or equal to 24 hours.

**III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.**

For each day, Demand Reduction Offers and, if applicable, Supply Offers of associated Net Supply Generator Assets, submitted into the Day-Ahead Energy Market and Real-Time Energy Market for the portion of a resource having a Capacity Supply Obligation must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.
III.13.6.1.5.3. Additional Requirements for Demand Resources.
Demand Resources shall comply with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:
(a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;
(b) 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 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.13.6.1.5.4. Demand Response Auditing.
Demand Resources shall be subject to ISO conducted audits for the purposes of:
(a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;
(b) Verifying the Commercial Operation of a Demand Resource; and
(c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.
(a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.
(b) The results of an audit shall be adjusted to reflect any changes in the composition of the Demand Resource resulting from the unmapping of a demand asset from the resource subsequent to the performance of the audit.

(c) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.

(d) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(e) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

(a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset and Net Supply Generator Asset that is mapped to each associated Demand Response Resource.

(b) The results of an audit shall be adjusted to reflect any changes in the composition of the Demand Response Resource resulting from the unmapping of a Demand Response Asset and Net Supply
Generator Asset from the Demand Response Resource subsequent to the performance of the audit.

(c) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section 8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(d) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2017, the audit results for Demand Response Resources comprised of Demand Response Assets and associated Net Supply Generator Assets that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2017 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

(e) If one or more Demand Response Assets of a Demand Response Resource or associated Net Supply Generator Assets do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets or associated Net Supply Generator Assets toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset or associated Net Supply Generator Asset was available for dispatch by the ISO in that prior month, and if the Demand Response Asset or associated Net Supply Generator Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset or associated Net Supply Generator Asset was available for dispatch.
III.13.6.1.5.4.3.1. **Seasonal DR Audit Requirement.**

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. **Failure to Request or Perform an Audit.**

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. **Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.**

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute notification time, may use the first 60 minute
period of the event after the 30 minute notification time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(c). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource’s audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource’s Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

### III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a Capacity Scarcity Condition Shortage Event as defined in Section III.13.7.1.1.1 or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4 that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets and associated Net Supply Generator Assets shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point (for the Demand Response Resource and its associated Net Supply Generator Assets) over the audit duration by proportionally reducing each associated Demand Response Asset’s and Net Supply Generator Asset’s audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the resource’s Audited Demand Reduction.

### III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource
Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) Demand Resource Commercial Operation Audits not performed prior to the commencement of the Capacity Commitment Period must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

(1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;

(2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource’s actual capability. Such criteria include, but are not limited to:

(a) A pattern of submitting to the ISO a level of available interruption that is less than the resource’s Demand Reduction Value or Audited Demand Reduction during the same time period;
(b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource’s Demand Reduction Value or Audited Demand Reduction; or

(c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset and associated Net Supply Generator Asset. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset and associated Net Supply Generator Asset to verify that the reported 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 measures in the demand asset or Demand Response Asset and associated Net Supply Generator Asset. 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 Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.
(a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.

(b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.

(c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.

(d) For Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Demand Response Capacity Resource will be based on the sum of the average load reductions or average Net Supply demonstrated during the audit by each Demand Response Asset and associated Net Supply Generator Asset associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource’s Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction plus the sum of the Economic Maximum Limits of any associated available Net Supply Generator Assets minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of the Net Supply Generator Asset is reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

(a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit
request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(b) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

c) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

(a) In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted; and

(b) For determination regarding termination under Section III.13.3.4(c).

(c) In the monthly calculation of a Demand Resource’s Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.
(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.
A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource’s Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource’s Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.
A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource’s monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. 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.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.


III.13.6.2.1.1.1. **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.13.6.2.1.1.2. **Real-Time Energy Market Participation.**

A Generating Capacity Resource having no 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, must Self-Schedule in order to participate 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.13.6.2.1.2. **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 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.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.
Settlement Only Resources 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;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.
III.13.6.2.5.1. Energy Market Offer Requirements.


For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market from such Demand Response Resources, the sum of the Demand Response Resource’s Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

For Supply Offers made into the Day-Ahead Energy Market and Real-Time Energy Market from such Net Supply Generator Assets, the sum of the Minimum Run Time plus the Minimum Down Time must also be less than or equal to 24 hours.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer or, for any associated Net Supply Generator Asset, a Supply Offer, into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer or Supply Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer or Supply Offer, up to the Maximum Reduction or 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 Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response 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 or, for any associated Net Supply Generator Assets, a Supply 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.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and 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. Demand Response Capacity Resources having no 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.13.6.3. 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.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand 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.

III.13.6.4. ISO Requests for Energy.

The ISO may request that a Demand Response Capacity Resource or Generating 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 Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that.
capacity that is not subject to a Capacity Supply Obligation. 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.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.
III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5. During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.


Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.


Generating Capacity Resources.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case of a
New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any Shortage Events during the month.

**III.13.7.1.2 Peak Energy Rents.**

Capacity Base Payments to resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as
provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

**III.13.7.1.2.1 Hourly PER Calculations.**

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER}\left(\$/kW\right) = [\text{LMP} - \text{Strike Price}] \times [\text{Scaling Factor}] \times [\text{Availability Factor}]
\]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.
(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run-time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

### III.13.7.1.2.2. Monthly PER Application

The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource’s PER deduction for an Obligation Month be less than zero or greater than the product of the resource’s Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

### III.13.7.1.1.1. Definition of Shortage Events

(a) In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the “minimum TMOR” requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) when Action 2 under Operating Procedure No. 4 has also been implemented for the entire Capacity Zone shall also be a Shortage Event. Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the “minimum TMOR” requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) shall also be a Shortage Event.
(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 event, that is declared for the entire import-constrained Capacity Zone for thirty or more contiguous minutes and that is not also declared for the entire Rest-of-Pool Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for the local Thirty-Minute Operating Reserves requirement (described in Section III.2.7A(c)) that is declared for the entire import-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource’s hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource’s Shortage Event Availability Score.

III.13.7.1.1.2 Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource’s availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource’s available MW in that hour plus any adjustments.
pursuant to Section III.13.7.1.1.4 divided by the resource’s Capacity Supply Obligation. In the event that
there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.
A resource’s available MW in each hour that contains any portion of a Shortage Event shall be
determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case
shall a resource’s available MW in an hour exceed that resource’s CNR Capability (reduced by the hourly-
integrated delivered MW for any External Transaction sale or sales from that resource or reduced by the
resource’s capacity obligation in an adjacent Control Area assigned to an external interface for which the
enhanced scheduling provisions in Section III.1.10.7.A are implemented).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch-
instructions, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted
or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and
following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes
or less, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or
redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and
following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or
equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with
notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the
Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the
listed portion of the resource was offered at or below the appropriate Reference Level plus applicable
conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30
minutes, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or
redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b)
or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.
(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource’s metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource’s available MW in an hour shall not be reduced as a result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource’s available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments

(a) A resource’s hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage
Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource’s Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource’s hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO’s annual maintenance scheduling process, or, for resources in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.10.7.A are implemented, when a Market Participant notifies the ISO, in accordance with the ISO’s annual maintenance scheduling process, that an asset associated with the External Resource is on an outage that was approved in the resource’s native Control Area. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource’s hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or.
demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource’s performance.

III.13.7.1.2. Import Capacity.

The provisions of this Section III.13.7.1.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). An Import Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource’s available MW in the hour shall be zero.
(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.1.3.7.1.2.A. Import Capacity on External Interfaces with Enhanced Scheduling.

The following available MW determination applies to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as designed in Section III.13.7.1.1.1. An Import Capacity Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.A.1). The available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation in the interval when the ISO requested delivery.

(b) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the available MW of a resource within that Control Area in the interval when the ISO requested delivery and that contains any portion of a Shortage Event shall be determined as follows:
(i) The quantity available is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;
(ii) The quantity available is the maximum output available from the resource, as reflected in the resource’s offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested delivery.

(c) If the ISO does not request MW of Import Capacity Resources, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation.

III.13.7.1.2.A.1. Availability Adjustments.

When the available MW of an Import Capacity Resource is calculated under Section III.13.7.1.2.A(b), the hourly availability score of any such Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource has complied with the provisions in Section III.13.7.1.1.4(b) for outage scheduling.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources, will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource’s metered output for the hour.
III.13.7.1.4.2. **Intermittent Settlement Only Resources**.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

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III.13.7.1.5. **Demand Resources**.

III.13.7.1.5.1. **Capacity Values of Demand Resources**.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

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III.13.7.1.5.1.1. **Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods**.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its
Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity-Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity-Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer-cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset’s monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer’s load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly
Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load
Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the
simple average of its monthly Demand Reduction Values in the most recent months of June, July and
August. The summer seasonal Demand Reduction Value shall apply to the months of September,
October, November, April and May.

III.13.7.1.5.4.2. **Winter Seasonal Demand Reduction Value.**
The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the
simple average of its monthly Demand Reduction Values in the most recent months of December and
January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. **Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.**
Monthly Demand Reduction Values shall be established for the months of June, July, August, December,
and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly
Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load
Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there
are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand
Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the
previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak
Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was
not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the
months of June or December, the Demand Reduction Value of that resource for those months shall be
equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit
conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to
the simple average of its monthly Demand Reduction Values in the most recent months of June, July and
August. This summer seasonal Demand Reduction Value will apply to the months of September, October,
November, April and May.
III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. Reserved.

III.13.7.1.5.6.1. Reserved.

III.13.7.1.5.6.2. Reserved.

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.
If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand
Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.
An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the
Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a
Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction-Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time-Emergency Generation Resource in that month.

III.13.7.1.5.8.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value for the months of September, October, November, April, and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. **Winter Seasonal Demand Reduction Value.**
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. **Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.**
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time-Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer-Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward-Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation.
and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.


An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.


Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity.
Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce demand, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource’s available MW in an hour exceed the resource’s Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail...
Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply-Generator Asset, shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(a) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instructions where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than (the Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (the resource’s Real-Time Demand Reduction Obligation plus the Net Supply for any associated available Net Supply Generator Assets) and the lesser of (the resource’s Demand Response Baseline as adjusted pursuant to Section III.SB.5 plus the Economic Maximum Limit for any associated available Net Supply Generator Assets), the resource’s Hourly Adjusted Audited Demand Reduction, or (the resource’s Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant).

(b) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instruction where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is equal to Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) or (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets) or total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than the Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has reduced demand or any associated Net Supply-Generator Assets have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation plus any associated Net Supply is less than the total Desired Dispatch-Point for the Demand Response Resource and the associated Net Supply-Generator Assets, the available-
MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net-Supply for the hour.

(d) For a Demand Response Resource that has reduced demand or any associated Net Supply-Generator Assets that have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the total Desired Dispatch Point for the Demand-Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the lesser of the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) of thirty-minutes or less, the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, and Actual Load) plus the sum of the Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty-minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full-Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, the resource’s Actual Load plus Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant or the resource’s Hourly-Adjusted Audited Demand Reduction time-weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.
(g) For a Demand Response Resource that (i) is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

### III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction

A Demand Response Resource’s Adjusted Audited Demand Reduction shall be determined as follows:

For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5 of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction set equal to the resource’s Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\text{Adjusted Audited Demand Reduction} = \frac{\text{The Audited Full Reduction Time (adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}}{\text{The Offered Full Reduction Time (adjusted for the Audited Demand Reduction)}} \times \text{the lesser of (the Audited Demand Reduction or (Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}.
\]

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction-
plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its
Adjusted Audited Demand Reduction calculated as:

$$\frac{(\text{the Offered Full Reduction Time adjusted for the Audited Demand Reduction})}{(\text{the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}} \times \min(\text{Audited Demand Reduction}, \max(\text{Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets}))$$

III.13.7.1.5.10.1.2 Hourly Adjusted Audited Demand Reduction

The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

III.13.7.1.5.10.2 Availability Adjustments

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Capacity Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource’s hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced reduction or scheduled reduction:
(i) A forced reduction can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced reduction. The forced reduction can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource.

(ii) A scheduled reduction must be submitted to the ISO at least 15 days ahead of the start of the reduction to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy-consuming equipment. The scheduled reduction cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource. Scheduled reductions must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus Economic Maximum Limit for any associated available Net Supply Generator Assets and Audited Demand Reduction adjusted down by the greater of (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets), or (Real-Time Demand Reduction Obligation plus Net Supply for any associated Net Supply Generator Assets). For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that as not received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Actual Load plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant, and the Audited Demand Reduction adjusted down by (the Maximum Reduction, as
submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any-
associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market-
Participant).

III.13.7.1.6. Self-Supplied FCA Resources.
Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their-
resource type.

III.13.7.2. Payments and Charges to Resources.
Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges-
in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed-
in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.
Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources-
designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month-
pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a-
Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments-
in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) Forward Capacity Auction. For a resource whose offer has cleared in a Forward Capacity-
Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case-
described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its-
audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England-
Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for-
resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in-
the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity-
Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment-
Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed-
using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the-
year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment-
Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

**III.13.7.2.2. Import Capacity.**

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

**III.13.7.1.32. Export Capacity.**

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

\[
\text{Charge Amount to Resource Exporting} = \left( \text{Capacity Clearing Price}_\text{location of the interface} - \text{Capacity Clearing Price}_\text{location of the resource} \right) \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid}
\]

\[
\text{Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located} = \left( \text{Capacity Clearing Price}_\text{location of the interface} - \text{Capacity Clearing Price}_\text{location of the resource} \right) \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid}
\]
Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.52.1.

**III.13.7.2.3. Intermittent Power Resources.**

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

**III.13.7.2.4. Settlement Only Resources.**

**III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.**

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

**III.13.7.2.4.2. Intermittent Settlement Only Resources.**

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

**III.13.7.2.5. Demand Resources.**

**III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.**

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

**III.13.7.1.42.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.**
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

### III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources
A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

### III.13.7.1.52.5.4. Energy Settlement for Real-Time Emergency Generation Resources
A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.1.5.12.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

### III.13.7.1.5.12.5.4.1 Adjustment for Net Supply Generator Assets
For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the
output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

### III.13.7.2.6. Self-Supplied FCA Resources

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

### III.13.7.2.7. Adjustments to Monthly Capacity Payments

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

### III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources

#### III.13.7.2.7.1.1. Peak Energy Rents

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

#### III.13.7.2.7.1.1.1. Hourly PER Calculations

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER} (\$/\text{kW}) = (\text{LMP} - \text{Strike Price}) \times \text{[Scaling Factor]} \times \text{[Availability Factor]}
\]

Where:
**NEPOOL PARTICIPANTS COMMITTEE**

**DEC. 6, 2013 MEETING, AGENDA ITEM #10**

**Attachment A**

**Strike Price** = the heat rate x fuel cost of the PER Proxy Unit described below.

**Scaling Factor** = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

**Availability Factor = 0.95**

(b) **PER Proxy Unit characteristics shall be as follows:**

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints.

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

**III.13.7.2.7.1.1.2 Monthly PER Application**

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:
PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2 Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.
(b) The penalty per resource for each Shortage Event shall be equal to:

\[
\text{Penalty} = \text{Resource's Annualized FCA Payment} \times PF \times [1 – \text{Shortage Event Availability Score}]
\]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource’s Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

\[PF = 0.05 \text{ for Shortage Events of 5 hours or less. PF is increased by 0.01 for each additional hour above 5 hours.}\]

III.13.7.2.7.1.3. Availability Penalty Caps

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) **Per Day.** In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource’s Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month.** The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.
III.13.7.2.7.1.4. Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the provisions in (a) and (b) below. In addition, all Import Capacity Resources will be subject to the provisions in (c) below.

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource’s Capacity Supply
Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction submitted under Section III.1.10.7 and associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

For Import Capacity Resources with a Capacity Obligation at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented (unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.), the requested and delivered MW are determined as follows:

(i) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the resources within that Control Area will not be evaluated for penalties.

(ii) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the resources will be evaluated using the following requested and delivered MW values:

1. The quantity requested is the resource’s Capacity Supply Obligation; and
2. The quantity delivered for a resource is determined as follows:

   a. The quantity delivered is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;
b. The quantity delivered is the maximum output available from the resource, as reflected in the resource’s offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested deliver;
c. For purposes of this determination, the total energy delivered will be adjusted in accordance with Section III.13.7.1.4(b).

(iii) If the ISO does not request MW of Import Capacity Resources, then the resources within that Control Area will not be evaluated for delivery penalties.

A Market Participant’s total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2. Exceptions.
The exceptions in Sections III.13.7.2.7.2.2.b, c and d do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

a) No penalty will be assessed if the applicable external interface is fully loaded in the import direction. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the-
associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

e) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.
Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.
Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.
For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.
III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource’s Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that
offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource's Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

**III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.**

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Penalties.
Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.
Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.
A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.
For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type.
(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 Real-Time Reserve Designation (including any regulation capability available but not used for energy) 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 resource’s Desired Dispatch Point 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 (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08.

(d) A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08.

(e) A Real-Time Emergency Generation Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; and shall be multiplied by 1.08.
(f) A Demand Response Capacity Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource’s Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.7.2.3 Capacity Balancing Ratio.
For each five-minute interval in which a Capacity Scarcity Condition exits, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

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\frac{(\text{Load} + \text{Reserve Requirement})}{\text{Total Capacity Supply Obligation}}
\]

(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.
(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning 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.

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves 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 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).

Reserve Requirement = the local Thirty-Minute Operating 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.

(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 local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve...
requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

(ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.
Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative.

III.13.7.2.5 Capacity Performance Payment Rate.
For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.
For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Payment for an interval shall equal the resource’s Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.
III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource’s Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource’s Capacity Base Payment for the Obligation Month plus the sum of the resource’s Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource’s Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource’s Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource’s Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5, the amount subtracted from the resource’s Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource’s Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

\[
\text{MaxCSO} \times [3 \text{ months } (\text{FCAcp} - \text{FCAsp}) - (12 \text{ months } \text{FCAcp})]
\]

Where:

MaxCSO = the resource’s highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.
FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource’s cumulative Capacity Performance Payments as the sum of the resource’s Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource’s Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource’s Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource’s Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource’s cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.3.3 Opt-Out for Resources Electing Multiple-Year Treatment.
Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline, opt out of the remaining years of the resource’s multiple-year election. A decision to so opt out shall be irrevocable. A resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.
For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 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.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(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 in proportion to each resource’s Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

III.13.7.53. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.2.1.27.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.32.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.
III.13.7.53.1. **Calculation of Capacity Requirement and Capacity Load Obligation.**

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; net load associated with an Alternative Technology Regulation Resource while providing Regulation; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity’s Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone’s Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity’s annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Commitment Period from the calendar year prior to the start of the Capacity Commitment Period.

A load serving entity’s Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.
III.13.7.53.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.53.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.53.1.3. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity’s Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.53.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.53.3.

III.13.7.53.3. Capacity Transfer Rights.

III.13.7.53.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights (“CTRs”) for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total
CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone’s Net Regional Clearing Price and absolute value of each Capacity Zone’s Capacity Load Obligations, as calculated in Section III.13.7.35.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.53.3.2(c), III.13.7.53.3.4, and III.13.7.53.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone’s portion of the CTR fund. The
The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.35.3.2.

III.13.7.35.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.35.1. Market Participants with CTRs specifically allocated under Section III.13.7.35.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface.** The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface.** Except as provided in Section III.13.7.35.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(c) **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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.35.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.35.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.35.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.35.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.
(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

### III.13.7.35.3.4. **Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.53.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.53.3.2.

### III.13.7.35.3.5. [Reserved.]

### III.13.7.35.3.6. **Specifically Allocated CTRs for Pool Planned Units.**

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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.
<table>
<thead>
<tr>
<th></th>
<th>Millstone 3</th>
<th>Seabrook</th>
<th>Stonybrook GT 1A</th>
<th>Stonybrook GT 1B</th>
<th>Stonybrook GT 1C</th>
<th>Stonybrook 2A</th>
<th>Stonybrook 2B</th>
<th>Wyman 4</th>
<th>Summer (MW)</th>
<th>Winter (MW)</th>
</tr>
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<tbody>
<tr>
<td>Nominal Summer</td>
<td>1155.001</td>
<td>1244.275</td>
<td>104.000</td>
<td>100.000</td>
<td>104.000</td>
<td>67.400</td>
<td>65.300</td>
<td>586.725</td>
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<td>(MW)</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Nominal Winter</td>
<td>1155.481</td>
<td>1244.275</td>
<td>119.000</td>
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<td>119.000</td>
<td>87.400</td>
<td>85.300</td>
<td>608.575</td>
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<tr>
<td>(MW)</td>
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</tr>
<tr>
<td>Danvers</td>
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<td>1.1124%</td>
<td>8.4569%</td>
<td>8.4569%</td>
<td>8.4569%</td>
<td>11.5551%</td>
<td>11.5551%</td>
<td>0.0000%</td>
<td>58.26</td>
<td>63.73</td>
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<td>0.7356%</td>
<td>0.7356%</td>
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<td>5.04</td>
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<tr>
<td>Ipswich</td>
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<td>0.1066%</td>
<td>0.2934%</td>
<td>0.2934%</td>
<td>0.2934%</td>
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<td>0.0000%</td>
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<td>2.93</td>
<td>2.37</td>
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<tr>
<td>Marblehead</td>
<td>0.1544%</td>
<td>0.1351%</td>
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<td>2.6840%</td>
<td>2.6840%</td>
<td>1.5980%</td>
<td>1.5980%</td>
<td>0.2793%</td>
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<td>Middleton</td>
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<td>0.3282%</td>
<td>0.8776%</td>
<td>0.8776%</td>
<td>0.8776%</td>
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<td>1.8916%</td>
<td>0.1012%</td>
<td>10.40</td>
<td>11.07</td>
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<tr>
<td>Peabody</td>
<td>0.2969%</td>
<td>1.1300%</td>
<td>13.0520%</td>
<td>13.0520%</td>
<td>13.0520%</td>
<td>0.0000%</td>
<td>0.0000%</td>
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<td>Reading</td>
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<td>14.4530%</td>
<td>14.4530%</td>
<td>14.4530%</td>
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<td>3.9929%</td>
<td>3.9929%</td>
<td>6.3791%</td>
<td>6.3791%</td>
<td>0.4398%</td>
<td>30.53</td>
<td>32.64</td>
</tr>
</tbody>
</table>
This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (“WRC”) any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

**III.13.7.35.4. Forward Capacity Market Net Charge Amount.**

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.
III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made by the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward 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;

(v) [reserved] the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor’s determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including
information regarding each of the elements considered in the Internal Market Monitor’s
determination of expected net revenues (other than revenues from ISO-administered markets) and
whether that element was included or excluded in the determination of whether the offer is
consistent with the resource’s long run average costs net of expected net revenues other than
capacity revenues;

(viii) the Internal Market Monitor’s determinations regarding offers or bids submitted during
the qualification process made according to the provisions of this Section III.13, including an
explanation of the reasons for rejecting any de-list bids from resources associated with pivotal
Lead Market Participants as described in Section III.13.1.2.3.2 based on the Internal Market
Monitor review and 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. The filing shall
identify to the extent possible the components of the bid which were accepted as justified, and
shall also identify to the extent possible the components of the bid which were not justified and
which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction
(this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity
Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described
in Section III.13.8.1(a) or in the qualification determination notifications described in Sections
III.13.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section
III.13.1.2.3.2.1.1, must be filed with the Commission no later than 15 days after the ISO’s submission
of the informational filing. If the Commission does not issue an order within 75 days after the ISO’s
submission of the informational filing that directs otherwise, the determinations contained in the
informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting
the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward
Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within
75 days after the ISO’s submission of the informational filing, the Commission does issue an order
modifying one or more of the ISO’s determinations, then the Forward Capacity Auction shall be
conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO’s filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.
(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. [Reserved.]
III.13.8.4. [Reserved.]
To: Participants Committee  
From: Alex Kuznecow, Secretary, Markets Committee  
Date: November 15, 2013  
Subject: ACTIONS OF THE MARKETS COMMITTEE

This memo is notification to the Participants Committee (PC) of the following actions taken by the Markets Committee (MC) at its November 13 and 14, 2013 meeting. All Sectors had a quorum.

1. (Agenda Item 1A) SEPTEMBER 20, 2013, OCTOBER 2, 2013 and OCTOBER 8 & 9, 2013 MC MEETING MINUTES
   ACTION: APPROVED

   It was moved, seconded and approved (with one abstention) by the Markets Committee on a show of hands to accept the minutes of the September 20th, October 2nd, and October 8th and 9th Markets Committee meetings.

2. (Agenda Item 2) FORWARD CAPACITY AUCTION #9 – OFFER REVIEW TRIGGER PRICES
   ACTION: MOTION FAILED

   The following motion was moved and seconded by the Markets Committee:

   RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Appendix A to Market Rule 1 implementing the proposed revisions to the Offer Review Trigger Prices (ORTP) for FCA #9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation (which must be addressed every third year) as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

   (Vote 1 – Passed (EnerNOC Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

   (1) Add a new Section III.13.1.4.2.4 to Market Rule 1 as follows:

   “III.13.1.4.2.4 Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers

   A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type.”
The motion to amend the main motion was then voted. The motion to amend passed with a vote of 68.86% in favor. The individual Sector votes were Generation (6.87% in favor, 10.3% opposed, 5 abstentions), Transmission (17.17% in favor, 0% opposed, 2 abstentions), Supplier (12.88% in favor, 4.29% opposed, 15 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (0.61% in favor, 16.56% opposed, 11 abstentions), and End User (17.17% in favor, 0% opposed).

(Vote 2 – Failed (NextEra Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Shore Wind</td>
<td>$0.008.53</td>
</tr>
</tbody>
</table>

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 32.43% in favor. The individual Sector votes were Generation (15.26% in favor, 1.91% opposed, 1 abstention), Transmission (0% in favor, 17.17% opposed), Supplier (17.17% in favor, 0% opposed, 10 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed, 30 abstentions), and End User (0% in favor, 17.17% opposed).

(Vote 3 – Passed (Energy Management, Inc. Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 by adding Off-Shore Wind to the table as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off-Shore Wind</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

The motion to amend the amended main motion was then voted. The motion to amend passed with a vote of 68.12% in favor. The individual Sector votes were Generation (2.45% in favor, 14.72% opposed, 3 abstentions), Transmission (17.17% in favor, 0% opposed), Supplier (0% in favor, 17.17% opposed, 12 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (17.17% in favor, 0% opposed, 38 abstentions), and End User (17.17% in favor, 0% opposed, 2 abstentions).

(Vote 4 – Failed (Exelon Amendment)) Before the twice-amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the twice-amended main motion as follows:

(1) Revise the ISO proposed Section III.A.21.1.1 of Market Rule 1 as follows:

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Offer Review Trigger Price ($/kW-month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>$13.42415.04</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>$8.86610.18</td>
</tr>
</tbody>
</table>
The motion to amend the twice-amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 5 – Failed) The twice-amended main motion was then voted. The twice-amended main motion failed with a vote of 56.24% in favor. The individual Sector votes were Generation (1.91% in favor, 15.26% opposed, 1 abstention), Transmission (17.17% in favor, 0% opposed), Supplier (1.91% in favor, 15.26% opposed, 9 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 2 abstentions), Publicly Owned Entity (3.92% in favor, 13.25% opposed, 4 abstentions), and End User (17.17% in favor, 0% opposed).

3. (Agenda Item 2) FORWARD CAPACITY AUCTION #9 – OFFER REVIEW TRIGGER PRICES
ACTION: VOTE FAILED

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO’s proposed revisions to Appendix A to Market Rule 1 implementing the proposed revisions to the Offer Review Trigger Prices (ORTP) for FCA #9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation.

The Markets Committee action on the ISO’s proposed revisions to Appendix A to Market Rule 1 resulted in a vote of 16.57% in favor. The individual Sector votes were Generation (0.95% in favor, 16.22% opposed), Transmission (8.58% in favor, 8.59% opposed, 2 abstentions), Supplier (2.15% in favor, 15.02% opposed, 10 abstentions), Alternative Resources (4.28% in favor, 9.89% opposed, 3 abstentions), Publicly Owned Entity (0.61% in favor, 16.56% opposed, 11 abstentions), and End User (0% in favor, 17.17% opposed, 1 abstention).

4. (Agenda Item 3) NCPC LOCAL SECOND CONTINGENCY PROTECTION RESOURCE COST ALLOCATION
ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Appendix F to Market Rule 1 to modify the cost allocation for Local Second Contingency Protection Resource requirements in the Day-Ahead Energy Market as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed with a vote of 80.61% in favor. The individual Sector votes were Generation (8.58% in favor, 8.59% opposed, 6 abstentions), Transmission (17.17% in favor, 0% opposed, 1 abstention), Supplier (6.36% in favor, 10.81% opposed, 16.3 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (17.17% in favor, 0% opposed), and End User (17.17% in favor, 0% opposed, 3 abstentions).
5. (Agenda Item 5) **FUEL SWITCHING: USE OF REFERENCE LEVEL AS THE SUPPLY OFFER**

**ACTION: RECOMMEND SUPPORT**

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1 to relocate the Appendix K to Market Rule 1 provisions to use a dual-fuel resource’s secondary fuel reference level as its supply offer following a fuel switch as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed. 6 abstentions within the Supplier Sector and 1 abstention within the Alternative Resources Sector were recorded.

6. (Agenda Item 6) **DEMAND RESPONSE BASELINE AND OUTAGES**

**ACTION: RECOMMEND SUPPORT**

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1 and Appendix E1 to Market Rule 1 to implement the Demand Resources Working Group recommended changes to the Demand Response Baseline to account for scheduled and forced curtailments of demand response assets as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed. 2 abstentions within the Generation Sector were recorded.

7. (Agenda Item 8) **DEMAND RESOURCES WORKING GROUP (DRWG) REFERRAL REQUEST**

**ACTION: REFERRED TO WORKING GROUP**

The following DRWG request was referred to the Demand Resources Working Group by the Markets Committee:

(1) Develop alternative auditing approach that addresses simultaneous RTDR-RTEG audit issue, and continues to avoid double-counting RTDR-RTEG capability.

8. (Agenda Item 13) **NEPOOL GIS OPERATING RULES WORKING GROUP REFERRAL REQUEST**

**ACTION: REFERRED TO WORKING GROUP**

The following NRG request was referred to the NEPOOL GIS Operating Rules Working Group by the Markets Committee:
1. Consider potential revisions to Rule 2.6 of the NEPOOL GIS Operating Rules relating to changes in assignments of Certificates.

9. (Agenda Item 14) **FCM PERFORMANCE INCENTIVES**

**ACTION: MOTION FAILED**

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2 to implement the FCM Performance Incentives proposal and mitigation design as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

**(Vote 1 – Failed (Brookfield Amendment #1))** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7.2.4 of Market Rule 1 in accordance with the Brookfield proposed changes regarding Intermittent Power Resources (see Brookfield Amendment #1).

The motion to amend the main motion was then voted. Based on a show of hands, the motion to amend failed.

**(Vote 2 – Failed (Brookfield Amendment #2))** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7.2.2 (b) of Market Rule 1 in accordance with the Brookfield proposed changes regarding Import Capacity Resources (see Brookfield Amendment #2).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 19.69% in favor. The individual Sector votes were Generation (0% in favor, 17.17% opposed, 3 abstentions), Transmission (0% in favor, 17.17% opposed, 1 abstention), Supplier (13.73% in favor, 3.44% opposed, 15 abstentions), Alternative Resources (5.47% in favor, 8.7% opposed, 4 abstentions), Publicly Owned Entity (0.49% in favor, 16.68% opposed, 2 abstentions), and End User (0% in favor, 17.17% opposed, 6 abstentions).

**(Vote 3 – Failed (NextEra Amendment))** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NextEra proposed changes (see NextEra Amendment).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 12.15% in favor. The individual Sector votes were Generation (2.15% in favor, 15.02% opposed, 2 abstentions), Transmission (0% in favor, 17.17% opposed), Supplier (5.72% in favor, 11.45% opposed, 14 abstentions), Alternative Resources (4.28% in favor, 9.89% opposed, 1 abstention),
Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (0% in favor, 17.17% opposed, 4 abstentions).

**Vote 4 – Failed (MMWEC Amendment)** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

1. Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the MMWEC proposed changes (see MMWEC Amendment).

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 49.35% in favor. The individual Sector votes were Generation (6.44% in favor, 10.73% opposed, 2 abstentions), Transmission (13.73% in favor, 3.44% opposed, 1 abstention), Supplier (8.58% in favor, 8.59% opposed, 14 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 1 abstention), Publicly Owned Entity (17.17% in favor, 0% opposed), and End User (3.43% in favor, 13.74% opposed, 8 abstentions).

**Vote 5 – Passed (Brookfield Amendment #3)** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

1. Revise the ISO proposed Section III.13.7.2.4 of Market Rule 1 in accordance with the Brookfield proposed changes regarding ISO imposed limitations due to transmission and other system issues (see Brookfield Amendment #3).

The motion to amend the main motion was then voted. The motion to amend passed with a vote of 71.77% in favor. The individual Sector votes were Generation (15.02% in favor, 2.15% opposed, 2 abstentions), Transmission (8.58% in favor, 8.59% opposed), Supplier (17.17% in favor, 0% opposed, 12 abstentions), Alternative Resources (14.17% in favor, 0% opposed), Publicly Owned Entity (2.52% in favor, 14.65% opposed, 5 abstentions), and End User (14.31% in favor, 2.86% opposed, 1 abstention).

**Vote 6 – Failed (NU Amendment #3)** Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Add a new Section III.13.7.2.7 to Market Rule 1 as follows:

   “III.13.7.2.7 Exception.

   (a) A resource’s Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver energy or reserves during that Capacity Scarcity Condition is due to an outage or de-rate of a transmission facility in the New England Control Area that is beyond the control of the resource.”

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 42.06% in favor. The individual Sector votes were Generation (3.43% in favor, 13.74% opposed), Transmission (17.17% in favor, 0% opposed), Supplier (0% in favor, 17.17% opposed, 11 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 2 abstentions), Publicly
Owned Entity (17.17% in favor, 0% opposed, 34 abstentions), and End User (4.29% in favor, 12.88% opposed, 5 abstentions).

**Vote 7 – Failed (EquiPower Amendment)** Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Add a new Section III.13.1.2.3.2.4.1 to Market Rule 1 as follows:

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“III.13.1.2.3.2.4.1 Static De-List Bids for Reductions in Ratings Due to EFORd

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects may not be physically available due expected unavailability represented by EFORd times summer Qualified Capacity at 90 degrees. EFORd shall be the value, as reported through GADS, for the most recent Capacity Commitment Period prior to time at which the FCM qualification process takes place. The ISO shall verify during the qualification process that the value is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.”
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The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

**Vote 8 – Failed (GDF SUEZ Amendment)** Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the GDF SUEZ proposed changes (see GDF SUEZ Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 45.12% in favor. The individual Sector votes were Generation (17.17% in favor, 0% opposed), Transmission (0% in favor, 17.17% opposed, 2 abstentions), Supplier (17.17% in favor, 0% opposed, 7 abstentions), Alternative Resources (5.88% in favor, 8.29% opposed), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (4.91% in favor, 12.26% opposed, 6 abstentions).

**Vote 9 – Failed (GDF SUEZ Alternative Amendment)** Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the GDF SUEZ proposed changes (see GDF SUEZ Alternative Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 45.16% in favor. The individual Sector votes were Generation (17.17% in favor, 0%
opposed, 1 abstention), Transmission (0% in favor, 17.17% opposed, 2 abstentions), Supplier (17.17% in favor, 0% opposed, 7 abstentions), Alternative Resources (10.83% in favor, 3.34% opposed, 2 abstentions), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (0% in favor, 17.17% opposed, 10 abstentions).

(Vote 10 – Failed (NU Amendment #1)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NU proposed changes regarding passive demand resources (see NU Amendment #1).

The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 11 – Failed (NU Amendment #2)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Revise the ISO proposed Section III.13.7 of Market Rule 1 in accordance with the NU proposed changes regarding existing generation (see NU Amendment #2).

The motion to amend the amended main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 12 – Failed (Dominion Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Replace the ISO FCM Performance Incentives proposal with revisions to existing Sections III.13.1, III.13.2, III.13.3, III.13.4, III.13.5 and III.13.8 of Market Rule 1, and the addition of a new Section III.13.7.3.1 to Market Rule 1 in accordance with the Dominion proposed changes (see Dominion Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 21.74% in favor. The individual Sector votes were Generation (11.44% in favor, 5.73% opposed, 4 abstentions), Transmission (0% in favor, 17.17% opposed), Supplier (10.3% in favor, 6.87% opposed, 15 abstentions), Alternative Resources (0% in favor, 14.17% opposed, 2 abstentions), Publicly Owned Entity (0% in favor, 17.17% opposed, 2 abstentions), and End User (0% in favor, 17.17% opposed, 3 abstentions).

(Vote 13 – Failed (NRG Amendment)) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

1. Replace the ISO FCM Performance Incentives proposal with revisions to existing Sections III.13.1, III.13.2, III.13.4, III.13.7 and III.13.8 of Market Rule 1 in accordance with the NRG proposed changes (see NRG Amendment).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 31.65% in favor. The individual Sector votes were Generation (12.88% in favor, 4.29%
opposed, 4 abstentions), Transmission (0% in favor, 17.17% opposed, 1 abstention), Supplier (17.17% in favor, 0% opposed, 12 abstentions), Alternative Resources (1.6% in favor, 12.57% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed, 10 abstentions), and End User (0% in favor, 17.17% opposed, 5 abstentions).

(Vote 14 – Failed) The amended main motion was then voted. Based on a show of hands, the amended main motion failed.

10. (Agenda Item 14) FCM PERFORMANCE INCENTIVES

ACTION: VOTE FAILED

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO’s proposed revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2 to implement its FCM Performance Incentives proposal and mitigation design.

Based on a show of hands, the Markets Committee failed to support the ISO’s proposed revisions to Market Rule 1, Appendix A to Market Rule 1, and Tariff Section I.2.2.
Proposed modifications to ISO’s proposed Pay-For-Performance FCM construct

Aleksandar Mitreski
NEPOOL Markets Committee
November 14th 2013

Brookfield Renewable Energy Group. Focusing on Renewable Power Generation and Transmission
About Brookfield Renewable

One of the largest public pure-play renewable power businesses in the world with 100 years of experience in power generation with predominantly hydro portfolio.

$17B
POWER GENERATING ASSETS

5,900
MEGAWATTS OF CAPACITY

84%
HYDROELECTRIC GENERATION

209 generating facilities

12 markets in 3 countries

Situated on 70 river systems
Proposed Changes to the FCM Pay-For-Performance Construct

Overview of Brookfield’s Proposed Changes

Proposing three areas of modification to the current FCM Pay-for-Performance construct

1. When a resource is subject to an ISO-imposed limit then the resource should not be penalized for non delivery of energy/reserves above that restriction
   – Only applicable for ISO-imposed limits that occur due to transmission issues, voltage issues, posturing, largest system contingency protection

2. Intermittent resources should not be penalized for non performance
   – This class of resources are already penalized through the discount in their determination of Qualified Capacity in FCM

3. External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols should not be penalized for non-performance
   – Should apply only to External Transactions that offered below the actual nodal LMP (i.e., were economic) of that scheduling interval, but were not cleared by the ISO to flow
1. Generator Limitation due to ISO-Imposed Limit

Premise (Generators) – At times ISO forecasts and informs a Market Participant that there is a system issue (e.g., transmission outage/line overload/voltage issue/posturing of a generator) that restricts the maximum amount of energy/reserves that can be delivered from a generator

- A Market Participant is obliged to follow those instructions and restrict output
  - For example assume transmission work in the area limits the maximum output of a generator from 100MW to only 25MW

- Unreasonable to expect the resource to deliver energy/reserves above the ISO-imposed limit of 25MW
  - But if the balancing ratio is .25, and this resource has a CSO of 100MW then this resource is expected to **fully deliver 25MW** during the scarcity period
1. Import Capacity Resource Limitation due to ISO-Imposed Limit

Premise (Import Capacity Resources) – At times ISO forecasts that there will be a transmission issue/largest contingency protection that limits the maximum amount of energy that can be delivered across an external interface.

• The Market Participants experience limitation of their desired flow (i.e., curtailments) due to the ISO-imposed limit (or the neighboring control area) across that interface.

• For example assume a Market Participant has a CSO from an Import Capacity Resource for 100MW and delivers the capacity/energy across an external interface with import capacity of 1,000MW. Assume an ISO-imposed limit reduces the maximum flow (i.e., TTC) across that interface to 800MW.

• Unreasonable to expect the resource to deliver is full CSO because it could be subject to curtailment due to the reliability issue.

  • Participant should be expected to deliver a pro-rata of its CSO according to the reduction (in this case a 20% reduction).

  • But if balancing ratio is .25, and this resource has a CSO of 100MW then this resource is expected to fully deliver 25MW.
1. Resource Limitation due to ISO Imposed Limit

Rationale - Following ISO dispatch instructions to restrict output/flow in order to alleviate a reliability constraint is a bedrock principle under which resources should never be penalized for non-performance.

- Unreasonable to expect that this resource should trade out part of its obligation, especially if ISO-imposed limit was received only several hours in advance.
- Resource is ready and available to perform up to its full CSO (e.g., it has fuel, made all appropriate scheduling arrangements).
- This resource is already incurring opportunity cost in the energy market for not being able to deliver energy/reserves due to the ISO-imposed limit. Additional FCM penalties exacerbate the lost revenue, especially since the cause of the ISO-imposed limit is beyond the control of the Market Participant.
Proposed Changes to the FCM Pay-For-Performance Proposal

1. Resource Limitation due to ISO Imposed Limit – Proposal

Proposal

1. When an ISO-imposed limit impacts the generator’s maximum output due to:
   - Transmission work/outage/thermal issue
   - Voltage issues on the system
   - Reduction in output to protect against largest contingency on the system or when postured

   • An “ISO-limited CSO” should be established for any generator whose output is restricted due to the ISO-imposed limit. Generators should not be subject to any non-delivery of energy/reserves above that “ISO-limited CSO” as currently proposed in the FCM Pay-for-Performance construct

2. When ISO-imposed limit (or a neighboring control area) reduces the maximum flow of energy (i.e., TTC) across an external interface due to reliability reasons then:

   • An “ISO-limited CSO” should be calculated for any Import Capacity Resource on a pro-rata of the reduction in the interface flow. Import Capacity Resources should not subject to any non-delivery of energy above that “ISO-limited CSO” as currently proposed in the FCM Pay-for-Performance construct

   • As a result, the Performance Payment Rate will be reduced to offset any ISO-imposed limits that occur during a scarcity event
2. Intermittent Resources are Already Subject to Reduced Revenue in FCM

Premise

• Inherent nature of intermittent resources is that they can not increase their output at all times

• ISO’s operational practice and planning procedures (i.e., ICR procurement) already account for the intermittent nature of resources

• The existing Qualified Capacity methodology already discounts the maximum CSO that an intermittent resource can obtain compared to its nameplate rating:
  – The Qualified Capacity is calculated as the average output of the resource during reliability hours (2 hours in the winter and 5 hours in summer) in the previous 5 years
    • For example a wind resource with Eco Max of 100MW may only receive a CSO for 20MW

• In many hours intermittent resources provide energy above their CSO
  – For example spring output of a run-of-river hydro resource
2. Intermittent Resources are Already Subject to Reduced Revenue in FCM

Rationale

• Intermittent resources are already penalized through shortfall in their capacity payment, compared to their capacity factor/nameplate rating/delivery of energy and should not be subject to the proposed non-delivery penalty

• FCM is one of the fundamental revenue streams for these types of resources

• Exposure to proposed non-delivery penalties creates significant risk to existing renewable resources and disincentive for investment in new ones (i.e., counterintuitive to existing renewable standards)

• The intermittent nature of these resources is already factored in the operating/planning process of the ISO
Proposed Changes to the FCM Pay-For-Performance Proposal

2. Intermittent Resources are Already Subject to Reduced Revenue in FCM - Proposal

Proposal

- Intermittent resources should not be penalized for any non-delivery as currently proposed in the FCM Pay-for-Performance construct
- Intermittent resources should be eligible to receive compensation for any energy/reserves delivered above the CSO x Balancing Ratio as currently proposed in the FCM Pay-for-Performance construct
  - This revenue will supplement some of the forgone revenue in the FCM due to the current Qualified Capacity methodology that is applied to intermittent resources
Proposed Changes to the FCM Pay-For-Performance Proposal

3. Import Capacity Resources Under the Proposed FCM PFP Construct

- Currently Import Capacity Resources are required to offer External Transactions below a threshold price. Subsequently, when ISO clears the transactions the Market Participant is responsible for ensuring that the energy flows into New England (i.e., delivers the energy).

- ISO proposes to eliminate the “offer below the threshold price” requirement, which may produce right behavior, but this change in isolation disregards the scheduling seams issues between neighboring control areas:
  - External Transactions do not have the flexibility (e.g., intra-hour self-scheduling) to react to any intra-hour scarcity event
  - Only with one neighboring control area (NY) the Coordinated Transaction Scheduling (CTS) is expected to be implemented (according to tentative implementation plans)
    - 15-minute scheduling will be in place, but intra-hour offer flexibility (re-offering of price) for External Transactions will not be allowed
  - With remaining control areas, scheduling of External Transactions will continue on an hourly basis

- External Transactions may be offered at a price that would be economic in a given hour, but may not be cleared to flow due to latency effect in the timing of the check-out protocol between control areas

- External Transactions may be offered at a price that would be economic in a given hour and may be cleared using a forecasted LMP, but the actual LMP may cause a loss for the Market Participant
Proposed Changes to the FCM Pay-For-Performance Proposal

3. Import Capacity Resources Under the Proposed FCM PFP Construct – Example 1

- Assume a non-CST interface on which for HE 15 and 16 an External Transaction backing an Import Capacity Resource was submitted for 50MW at $100/MWh.
  - Assume the ISO forecast the nodal LMP of that interface at $90 so the transaction does not clear for HE 15
  - Assume a contingency occurs at 14:10 and the LMP during that hour increases to $150/MWh
    - This transaction would have flowed had there been a more dynamic scheduling practice
    - Analogously, since the unit dispatch system cases are performed more frequently, a fast start generator might have been dispatched on-line
  - Alternatively, assume a contingency occurs at 14:40 causing the LMP to increase to $150/MWh. The check-out between neighboring control areas for HE 16 has already been completed (at approximately 16:30) with nodal forecasted LMP of $95. The transactions does not clear for HE 16
    - This transaction would have flowed had there been a more dynamic scheduling practice

- The external transaction would have been economic in both hours (and is in the best economic interest of the Market Participant for those transactions to have flowed) if there was a more dynamic scheduling process between the two control areas
Proposed Changes to the FCM Pay-For-Performance Proposal

3. Import Capacity Resources Under the Proposed FCM PFP Construct – Example 2

• Assume a CST interface where a for HE 15 an External Transaction is offered at a spread of +$5 between NY and NE. CTS forecasts that the spread is +3 for the first 15-minute interval of that hour and does not clear the transaction
  – While transactions will be re-cleared every 15 minutes, there still exists a latency between the forecasted LMP and the actual LMP that occurs in any 15-minute interval
  – If there is a scarcity event in that first 15-minute interval, the spread between NY and NE may actually increase to $10
  – The external transaction appears to have been economic during that first 15-minute interval, but due to latency of the scheduling practices the current FCM Pay-for-Performance construct would not create a non-delivery penalty
  – External Transactions do not enjoy the benefit of providing reserves, although energy flow can be scheduled with a 15-minute notice on the interface
3. Import Capacity Resources Under the Proposed FCM PFP Construct – Proposal

Proposal

• Remove the current offer threshold requirement and evaluate the economics of External Transactions supporting Import Capacity Resources

• Import Capacity Resources should be penalized for non-delivery if deemed to offer uneconomically:
  – For example, an External Transaction was offered at $300/MWh and the actual LMP during that hour was $80/MWh, and an FCM scarcity event occurred, non-delivery penalty should be applied
  – Continue penalizing if ISO clears an External Transaction but the transaction does not flow (i.e., the Market Participant did not make the necessary scheduling arrangements)
3. Import Capacity Resources Under the Proposed FCM PFP Construct – Proposal

Proposal cont.

• Import Capacity Resources should not be penalized for non-delivery if:
  – External Transactions would have been deemed to be economic in a given scheduling interval (15-minutes for NY once CTS is implemented, 1 hour for remaining interfaces)
    • This determination is accomplished through a look-back in the scheduling interval to determine if the price of the External Transactions would have been economic compared to the actual ex-post LMP/interface spread (not the forecasted ex-ante LMP for that scheduling interval)
    • For example if an External Transaction was offered at $100 and the actual hourly LMP was $150/MWh, but the ISO did not clear that transaction, no FCM penalty should be applied
**BROOKFIELD AMENDMENT #1**

Brookfield Market Rule revisions regarding intermittent resources is highlighted in gray

**III.13.7.2.4 Capacity Performance Score.**

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative except that for Intermittent Power Resources the Capacity Performance Score shall be set to zero if calculated as negative.
Brookfield Market Rule revisions regarding import capacity resources is highlighted in gray

### III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type.

(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 Real-Time Reserve Designation (including any regulation capability available but not used for energy) 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 resource’s Desired Dispatch Point 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 External Transaction that may or may not be supporting an Import Capacity Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred or the energy that would have been delivered (but not less than zero) from External Transaction which was offered at a price that was below the LMP at that interface 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.
BROOKFIELD AMENDMENT #3

Brookfield’s Market Rule revisions regarding ISO imposed limitations due to transmission and other system issues is highlighted in gray.

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. The resulting Capacity Performance Score may be positive or negative. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio unless subject to the following provisions:

a) For Generating Capacity Resources or Demand Response Capacity Resources, in the event that the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio exceeds an ISO imposed restriction to the maximum output or minimum consumption of the resource (e.g., Economic Max) during a Capacity Scarcity Condition due to a transmission outage, derate, voltage issue, or restricting the maximum output of the resource for largest contingency protection then the Capacity Performance Score shall equal the Actual Capacity Provided during the interval minus the minimum of:
   i. The resource’s Capacity Supply Obligation multiplied by the applicable Capacity Balancing Ratio, or
   ii. The value of the output limitation imposed by the ISO

b) For Import Capacity Resources, in the event that the ISO or a neighboring Control Area imposes a restriction on the import interface limit across the applicable interface due to reliability reasons or transmission outages causing the import interface limit to be lower than the sum of the Capacity Supply Obligation of the Import Capacity Resources then the resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the:
   i. Resource’s Capacity Supply Obligation
   ii. Applicable Capacity Balancing Ratio
   iii. Derated import interface limit as restricted by the ISO or a neighboring Control Area divided by the sum of the Capacity Supply Obligations of the Import Capacity Resources.
Proposal for Performance Incentives

Michelle C. Gardner
NextEra Energy Resources

Markets Committee
October 29, 2013
NextEra is sponsoring a *package* of amendments needed to improve Performance Incentives

**A Three-Part Package**

- **No Phase-In of the Performance Payment Rate**
  - $5,455 starting with FCA-9

- **Revisions to Monthly Stop Loss**
  - “Minimum Hour Rule”

- **Transmission Exemption**
  - Full outages
Changing the PPR will significantly alter investment incentives and the system’s resource mix

**PPR Should Remain at $5,455 with No Phase-In**

- PPR set at $5,455 for FCA-9 with no further changes
- PPR and LMP together need to provide the right incentives to deliver energy and reserves during scarcity conditions (ISO-NE Memo, September 4, 2013)
- If PPR is too low, ISO-NE concludes that the following can occur (ISO-NE Memo, September 4, 2013):
  - Resources with poor performance may clear in the FCA, displacing competing resources with substantially better performance
  - The market produces a worse-performing resource mix, which lowers the amount of energy and reserves the ISO can expect to obtain during tight system conditions when reliability is at heightened risk; and
  - Perversely, with a lower PPR, suppliers find poor performance can be more profitable than better performance
Stop Loss (and exemption) should limit risk – not PPR

Revisions to Monthly Stop Loss

- Create a “Minimum Hour Rule” to provide greater management of risk during low capacity clearing prices
- For the capacity clearing price:
  - At or below $4/kW-month, the monthly stop-loss is $10/kW minus the capacity clearing price
  - Between $4/kW-month and $6/kW-month, the monthly stop-loss is 1.5 times the capacity clearing price
  - At or above $6/kW-month, the monthly stop-loss is $15/kW minus the capacity clearing price
- NextEra supports ISO-NE’s Annual Stop Loss Construct, provided NextEra’s monthly stop loss limits are adopted
ISO-NE’s proposed monthly stop loss places unreasonable economic risk on capacity suppliers, particularly when capacity clearing prices are low

**Revisions to Monthly Stop Loss**

**PPR at $5,455 with Balancing Ratio at 0.75 for 100 MW Unit**

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<th>Total Net Loss Revenue</th>
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The stop loss alone does not mitigate potentially catastrophic transmission outage risk

**Transmission Exemption**

- If a Capacity Resource cannot be committed because of a Transmission Outage, it will be excused from paying any PI penalties during the term of the Transmission Outage
  
  - PI is intended to provide incentives for capacity suppliers to have their resources operating during periods of greatest needs. Since transmission outages are beyond the control of capacity suppliers, it is unclear what reliability benefit could occur by charging PI payments when transmission outages keep a Capacity Resource off-line

- Exemption from PI payments applies during a Capacity Shortage Condition if that resource was not committed solely as a result of a transmission outage or transmission de-rating

- Exemption does not apply when transmission congestion on the intact transmission system results in a resource not being committed or dispatched
SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN
III.13. **Forward Capacity Market.**

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a descending clock auction ("Forward Capacity Auction") in accordance with the provisions of Section III.13.2 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 Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1. A Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.


To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.2.2.4.


A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.2.
III.13.1.1.1. **Resources Never Previously Counted as Capacity.**

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. **Resources Previously Counted as Capacity.**

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:
(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource’s summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource’s summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and
(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource’s Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.3 causes the resource to exceed the megawatt amount approved in the resource’s Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The
$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.3 or Section III.13.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.6. Treatment of Deactivated and Retired Units.
(a) [Reserved.]

(b) 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. 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), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

For a resource to qualify as a New Generating Capacity Resource, the resource’s Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project
Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

### III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website.
A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor’s contact information; the Project Sponsor’s ISO customer status; the project’s expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff.
A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option,
exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.2.2.2(d) and that accounts for more than five percent of the total project cost.
(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.2.2.3. **Offer Information.**

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.
(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity 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 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.
In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.
In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail.
to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.3(b), and III.13.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, or III.13.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.
III.13.1.2.3.  Initial Interconnection Analysis.

(a)  For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b)  If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource’s Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c)  If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.
(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).
(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.
The ISO shall review a New Generating Capacity Resource’s New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource’s claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.2.3(b). The FCA Qualified Capacity for such a 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.

III.13.1.2.5.2. [Reserved]

III.13.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource’s summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.
III.13.1.2.6.  [Reserved.]

III.13.1.2.7.  Opportunity to Consult with Project Sponsor.
In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor 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 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 believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor 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.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a)  whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b)  whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource’s New Capacity Qualification Package was not accepted;

(c)  if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.2.3(d);
(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource’s summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor’s determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.
An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.2.2.1.1. **Summer Qualified Capacity.**

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. **Winter Qualified Capacity.**

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource
shall be equal to the median of all of that Existing Generating Capacity Resource’s previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource’s net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource’s or Intermittent Settlement Only Resource’s summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.1(a).
(c) 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 the ISO has declared a system-wide Capacity Scarcity Condition Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource’s and Intermittent Settlement Only Resource’s winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 the ISO has declared a system-wide Capacity Scarcity Condition Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions Shortage Events in that Capacity Zone.
(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s winter Qualified Capacity
shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

### III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource’s summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, 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 Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing
Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

### III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource’s summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

#### III.13.1.2.2.5.1. [Reserved.]

#### III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource’s summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal
Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.5.2 shall be subject to a reliability review as described in Section III.13.2.5.2.5, as required. This Section III.13.1.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource’s Lead Market Participant of the resource’s summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating
Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

### III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to opt out of the capacity market at prices at or above $1.00/kW-month during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the
Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. **Permanent De-List Bids.**

An Existing Generating Capacity Resource seeking to opt out of the capacity market permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource’s full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. **Export Bids.**

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above $1.00/kW-month are subject to review by the Internal
Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

**III.13.1.2.3.1.4. Administrative Export De-List Bids.**

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).
III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.
A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.
The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.
The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.
A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.
III.13.1.2.3.1.6.  Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1.  Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist 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.

III.13.1.2.3.1.6.2.  [Reserved.]

III.13.1.2.3.1.6.3.  Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing 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 de-list 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 de-listing of each individual asset in preferred de-list 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 bids 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 bids 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 Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above $1.00/kW-month, and Permanent De-List Bids Above $1.00/kW-month.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above $1.00/kW-month, and each Permanent De-List Bid above $1.00/kW-month to determine whether the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.1) and opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.2). Sufficient documentation and information must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs and 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 resource, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.
The Internal Market Monitor may seek additional information from the Lead Market Participant after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

In the case of a Permanent De-List Bid or an Export Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing
Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

(b) In the case of a Static De-List Bid, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.2. Net Risk-Adjusted Going Forward Costs.
A Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month shall be considered consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

\[
\left( \frac{GFC}{(AA)} + \left[ RF - (IMR - PER) \right] \right) \times \text{InfIndex} \\
\frac{(CQ_{\text{Summer}}, kW) \times (12, months)}{}
\]

Where:

GFC = annual going forward costs, in dollars. These are costs 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 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 Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

\[
CQ_{\text{Summer}}kW = \text{capacity seeking to de-list in kW}. \text{In no case shall this value exceed the resource’s summer Qualified Capacity.}
\]
RF = risk factor, in dollars. This value shall be calculated using the following formula:

\[
RF = [(RPC \times EFORd) + (P \times (Forward\ \text{Capacity\ Auction\ Starting\ Price} - AFCAP)) \times 12,\text{months}]] \times CQ_{\text{Summer kW}}
\]

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit’s daily price to the resource’s Real-Time nodal price. For each hour that the resource’s nodal price exceeds the PER Proxy Unit’s daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit’s daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.

P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource’s Capacity Zone.

AA = availability adjustment. AA = (1 − EFORd)
Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual 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 Existing Generating Capacity Resource’s total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource’s total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.

InfIndex = inflation index. \( \text{InfIndex} = (1 + i)^4 \)

Where: “\(i\)” is the most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.
III.13.1.2.3.2.1.3. **Opportunity Costs.**

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month has opportunity costs that support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, 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. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. **Administrative Export De-List Bids.**

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. **Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.**

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered
into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

**III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.**

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

<table>
<thead>
<tr>
<th>Age of Existing Resource (years)</th>
<th>Remaining Life (years)</th>
<th>Annual Rate of Capital Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 to 5</td>
<td>30</td>
<td>0.106</td>
</tr>
<tr>
<td>6 to 10</td>
<td>25</td>
<td>0.110</td>
</tr>
<tr>
<td>11 to 15</td>
<td>20</td>
<td>0.117</td>
</tr>
<tr>
<td>16 to 20</td>
<td>15</td>
<td>0.131</td>
</tr>
<tr>
<td>21 to 25</td>
<td>10</td>
<td>0.163</td>
</tr>
<tr>
<td>25 plus</td>
<td>5</td>
<td>0.264</td>
</tr>
</tbody>
</table>

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

\[
\text{Annual Rate of Capital Cost Recovery} = \frac{\text{Cost Of Capital}}{(1 - (1 + \text{Cost Of Capital})^{-\text{Remaining Life}})}
\]

Where:
Cost Of Capital = the adjusted pre-tax weighted average cost of capital.
Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.
III.13.1.3. **Import Capacity.**

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

<table>
<thead>
<tr>
<th>External Node Common Name</th>
<th>Capacity Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>NB-NE External Node</td>
<td>Maine</td>
</tr>
<tr>
<td>HQ Phase I/II External Node</td>
<td>Rest-of-Pool</td>
</tr>
<tr>
<td>Highgate External Node</td>
<td>Rest-of-Pool</td>
</tr>
<tr>
<td>NY-NE AC External Node</td>
<td>Rest-of-Pool</td>
</tr>
<tr>
<td>Cross Sound Cable External Node</td>
<td>CT</td>
</tr>
</tbody>
</table>

III.13.1.3.1. **Definition of Existing Import Capacity Resource.**

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. **Qualified Capacity for Existing Import Capacity Resources.**
The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.
Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO
documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

<table>
<thead>
<tr>
<th>Contract Description</th>
<th>MW</th>
<th>Contract End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYPA: NY — NE: CMEEC</td>
<td>13.2</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY — NE: MMWEC</td>
<td>53.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY — NE: Pascoag</td>
<td>2.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>NYPA: NY — NE: VELCO</td>
<td>15.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td></td>
<td>84.1</td>
<td></td>
</tr>
<tr>
<td>VJO: Highgate — NE</td>
<td>Up to 225</td>
<td>10/31/2016</td>
</tr>
<tr>
<td>VJO: Highgate — NE (extension)</td>
<td>Up to 6</td>
<td>October 2020 (beginning 11/01/2016)</td>
</tr>
<tr>
<td>VJO: Phase I/II — NE</td>
<td>Up to 110</td>
<td>10/31/2016</td>
</tr>
</tbody>
</table>

III.13.1.3.4. Definition of New Import Capacity Resource.
Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.
The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same
as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.
For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New 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 (iv) documentation for system-backed import capacity that the import capacity 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. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England’s import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project’s equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.
If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or
controlled directly by the 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 New Import Capacity Resource’s potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.
If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.
The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, 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 Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification 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. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.
III.13.1.3.5.4.  Capacity Commitment Period Election.
The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5.  Initial Interconnection Analysis.
The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6.  Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.
In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7.  Qualification Determination Notification for New Import Capacity Resources.
For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8.  Rationing Election.
The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4.  Demand Resources.
III.13.1.4.1. **Demand Resources.**

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand 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 Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

**III.13.1.4.1.1. Existing Demand Resources.**

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets.
associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.
A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.
For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource’s Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources
For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements
of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

**III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.**

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

**III.13.1.4.2. Show of Interest Form for New Demand Resources.**

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer
and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor’s New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.
For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no
later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.
The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.
For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.
A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With a Demand Reduction Value Greater Than or Equal to 5 MW.
For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.
III.13.1.4.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor’s capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete.

III.13.1.4.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor’s ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor’s program to deliver capacity to meet the Demand Resource Project Sponsor’s Forward Capacity Auction obligations, and must include each customer’s projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor’s ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource
Project Sponsor shall be subject to the ISO’s critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor’s New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.
A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. **Offers From New Demand Resources.**

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource’s costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. **Notification of Qualification for Demand Resources.**

III.13.1.4.2.5.1. **Evaluation of Demand Resource Qualification Materials.**

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;
(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.
For each Existing Demand Resource, the ISO will notify the Resource’s Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO’s notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.
No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

### III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource’s summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

### III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

### III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. 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.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.
III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project’s Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource’s Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor’s total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor’s total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports 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 Demand Resource Project Sponsors. 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.
III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.
At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.
At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor’s offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.
Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue 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 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.
For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors 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 Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor 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 Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.
For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource’s Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation.

For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.
The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

### III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

### III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

#### III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

#### III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.
III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.


A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at 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 and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.
III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.
relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant’s Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant’s right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]


A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers’ demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers’ demand response to be bid into the ISO-administered markets or programs.


A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail
regulatory authority prohibits such customer’s demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.


If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer’s facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO’s asset registration system, to which the end-use customer’s facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource’s highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource’s highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after
the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) 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 (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered 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 an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources 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.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources 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) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource’s final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource’s financial assurance requirements in accordance with Section III.13.1.9.


Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c).
and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity’s share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand 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.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity’s projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity’s most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource’s summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.
In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource’s summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above $1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.
(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. **Financial Assurance.**

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. **Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.**

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource’s financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.
III.13.1.9.2. **Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.**

Where a New Generating Capacity Resource’s offer or a New Demand Resource’s offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. **Failure to Provide Financial Assurance or to Meet Milestone.**

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. **Release of Financial Assurance.**

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, 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 an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand 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 resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. **Forfeit of Financial Assurance.**

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. **Financial Assurance for New Import Capacity Resources.**
A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.


For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual 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. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including
the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

<table>
<thead>
<tr>
<th>New Generating Resources ≥ 20 MW</th>
<th>New Generating Resources &lt; 20 MW and ≥ 2 MW</th>
<th>Imports and New Demand Resources (including Distributed Generation)</th>
<th>New Generating Resources &lt; 2 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td>Including Up-rates, Re-powering, Environmental Compliance &amp; Intermittent Power Resources</td>
<td>$25,000</td>
<td>$7,500</td>
</tr>
<tr>
<td>$25,000</td>
<td>$7,500</td>
<td>$1,000</td>
<td>$500</td>
</tr>
<tr>
<td>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</td>
<td>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</td>
<td>$15,000</td>
<td>$6500</td>
</tr>
<tr>
<td>$15,000</td>
<td>$6500</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor 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. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds 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, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If 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 exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.
Cost reimbursements received (excluding amounts passed through to the ISO’s consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.


The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.
<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
</table>
Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in year “X”, where X is any year after 2015.

<table>
<thead>
<tr>
<th>New Capacity Show of Interest Submission Window</th>
<th>Existing Capacity Qualification Deadline</th>
<th>New Capacity Qualification Deadline</th>
<th>First Day of Forward Capacity Auction for the Capacity Commitment Period</th>
<th>Capacity Commitment Period Begins</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feb. (X-4)</td>
<td>June (X-4)</td>
<td>June/July (X-4)</td>
<td>Feb. (X-3)</td>
<td>June X</td>
</tr>
</tbody>
</table>

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price
associated with a round of the Forward Capacity Auction). If a Capacity Zone has a Forward Capacity Auction Starting Price (determined in accordance with Section III.13.2.4) below the End-of-Round Price, then that Capacity Zone shall not be included in the round. In the first round, the Start-of-Round Price shall equal the highest Forward Capacity Auction Starting Price of all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic
Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be $P_S$ and $P_E$, respectively. Let the $m$ prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor’s supply curve, for all prices strictly less than $P_S$ but greater than or equal to $P_E$, shall be taken to be:

$$S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\vdots & \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}$$

where, in the first round, $q_0$ is the resource’s full FCA Qualified Capacity and, in subsequent rounds, $q_0$ is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and
is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round’s relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any
price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a
dependency review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be
included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b).
Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the
Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity
Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity
associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in
subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor
elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a
Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export
Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-
quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs
associated with another bid for the same resource.

(e) **Repowering.** Offers and bids associated with a resource participating in the Forward Capacity
Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2.2.4 (resources previously
counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the
provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity
Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other
New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is
offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that
the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of
capacity offered from the associated Existing Generating Capacity Resource shall not be included in the
aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward
Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as
of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the
New Generating Capacity Resource, then the auctioneer shall include capacity from the associated
Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the
qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5.
Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource
pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the
associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction
reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be
subject to the reliability review described in Section III.13.2.5.2.5.
(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. **Step 3: Determination of the Outcome of Each Round.**
The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the “Total System
Capacity”) shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, the total capacity associated with any Capacity Zone at any price greater than the Forward Capacity Auction Starting Price for that Capacity Zone is taken to be the total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

1. the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone’s Local Sourcing Requirement; or

2. the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded, except as required to minimize the total cost for the associated Capacity Commitment Period, as described in Section III.13.2.7, and such Capacity Zone will not be included in further rounds of the Forward Capacity...
Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.** For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded, except as required to minimize the total cost for the associated Capacity Commitment Period, as described in Section III.13.2.7, and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone’s Maximum Capacity Limit; and
(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded, except as required to minimize the total cost for the associated Capacity Commitment Period, as described in Section III.13.2.7, and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply
curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) Treatment of Export Capacity. Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.
(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

**III.13.2.3.4. Determination of Final Capacity Zones.**

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

**III.13.2.4. Forward Capacity Auction Starting Price.**
The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

**III.13.2.5.** Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

**III.13.2.5.1.** Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the total costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

**III.13.2.5.2.** Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

**III.13.2.5.2.1.** Permanent De-List Bids.
Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.
Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.
A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.
An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.
The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected.
pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that its bid did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue
operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.
In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, 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. For de-list bids, this review and update will follow ISO’s filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price.
Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service
compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the
Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ISO New England: A resource seeking to avail itself of the recovery mechanism provided in this Section 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, 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 III.13.2.5.2.5.1(c), 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.

**III.13.2.5.2.5.3. Retirement of Resources**

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will
be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn.
voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).


Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.
The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock
Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this
Section III.13.2.

***III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.***
The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity
Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the
Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price
in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be
paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated
Capacity Commitment Period.

***III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.***
The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity
Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the
Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing
Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone
shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the
associated Capacity Commitment Period.

***III.13.2.7.3. Capacity Clearing Price Floor.***
In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June
1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity
Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward
Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the
Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the
Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no
more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity
Auction, as follows:
(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.
At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):
(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine whether to clear more excess capacity at a lower Capacity Clearing Price or to clear less or no excess capacity at a higher Capacity Clearing Price, and shall choose the alternative that results in procuring at least the amount of capacity required while seeking to minimize the total cost for the associated Capacity Commitment Period by enumerating as many combinations of non-rationable offers and bids as practicable. In an import-constrained Capacity Zone, the cost minimization will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone’s Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The cost minimization may result in offers below the Capacity Clearing Price not clearing, and in
certain de-list bids (Permanent De-List Bids and Dynamic De-List Bids) below the Capacity Clearing Price clearing.

III.13.2.7.5. **Effect of Decremental Repowerings on the Capacity Clearing Price.**
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize total capacity costs.

III.13.2.7.6. **Minimum Capacity Award.**
Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. **Tie-Breaking Rules.**
Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum total costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal total costs, the offer associated with the resource with the higher queue priority shall clear.
(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.
The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then
the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. **Inadequate Supply and Insufficient Competition.**
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. **Inadequate Supply.**

III.13.2.8.1.1. **Inadequate Supply in an Import-Constrained Capacity Zone.**
An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone’s Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof,
that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).
(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:
(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.13.2.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]
III.13.3.  Critical Path Schedule Monitoring.

III.13.3.1.  Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1.  New Resources Clearing in the Forward Capacity Auction.
   For each new resource required to submit a critical path schedule in the qualification process, including a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), or a New Demand Resource (pursuant to Section III.13.1.4), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource’s compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 from the time that the Forward Capacity Auction is conducted until the resource achieves Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4(c), or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.2.  New Resources Not Offering or Not Clearing in the Forward Capacity Auction.
   If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource’s compliance with its critical path schedule after the Forward Capacity Auction unless, within 5 Business Days after the Forward Capacity Auction is completed, the Project Sponsor for that resource requests in writing that the ISO continue to monitor that resource’s compliance with its critical path schedule. A New Generating Capacity Resource may not, however, request that the ISO continue to monitor that resource’s compliance with its critical path schedule pursuant to this Section III.13.3.1.2 if that resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Generating Capacity Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Generating Capacity Resource.

III.13.3.2.  Quarterly Critical Path Schedule Reports.
   For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor 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 Project Sponsor 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 Project Sponsor. If the Project Sponsor 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.13.3.4(c). Each critical path schedule report shall include the following:

III.13.3.2.1. **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.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor 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 Project Sponsor should 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.13.3.2.2. **Documentation of Milestones Achieved.**
(a) For all new resources except for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 component, subsequent Commercial Operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation 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 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.** If during the qualification process it was determined that, because of overlapping interconnection impacts, transmission upgrades are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Resource projects installed at multiple facilities and Demand Resource projects 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 Project Sponsor 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 Project Sponsor shall provide documentation showing the total offered Demand Reduction Value achieved as of target dates which are: (a) the cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource supplier’s capacity award was made; (b) the cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource supplier’s capacity award was made; and (c) target date 3 which is the date the resource is expected to achieve commercial operation, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total Demand Reduction Value must be complete.

(ii) **Pipeline Analysis.** If the Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then the Project Sponsor shall provide a pipeline analysis to the ISO as specified in Section III.13.1.4.2.2.4.3 of Market Rule 1.

(iii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor 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 Project Sponsor shall also provide the asset identification number.

III.13.3.2.3. Additional Relevant Information.
The Project Sponsor 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 or the feasibility that the project will meet the requirement that the project achieve Commercial Operation no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.
For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, or III.13.1.1.4 or New Demand Resource pursuant to Section III.13.1.4.1.2 and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource’s Capacity Supply Obligation in accordance with the provisions of Section III.13.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.2, III.13.1.1.3, and III.13.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.
If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor 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 including Commercial Operation of the project. If a milestone date is revised for any reason, the ISO may require the Project Sponsor 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 Project Sponsor 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 Project Sponsor. If the Project Sponsor 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.13.3.4(c). Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.
III.13.3.4. Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.

If as a result of milestone date revisions made pursuant to Section III.13.3.3, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except for a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation in the circumstances described in Section III.13.7.1.1.3(h) and Section III.13.7.1.1.3(i)), then the Project Sponsor must take actions to cover the entire Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, as follows:

(a) The Project Sponsor may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4 or one or more Capacity Supply Obligation Bilaterals, which must be submitted to the ISO as described in Section III.13.5.

(b) If, by the time demand bids are due for the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, the Project Sponsor has not covered its full Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, then the ISO shall submit a demand bid in that annual reconfiguration auction on the Project Sponsor’s behalf for a quantity equal to the largest monthly Capacity Supply Obligation for the Capacity Commitment Period that has not been covered, at the Forward Capacity Auction Starting Price (with all payments, charges, rights, obligations, and other results associated with such demand bid applying to the Project Sponsor as if the Project Sponsor itself had submitted the demand bid).

(c) If the Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if the Capacity Supply Obligation is not covered as described in Sections III.13.3.4(a) and III.13.3.4(b), or if the Project Sponsor covers the Capacity Supply Obligation for two Capacity Commitment Periods, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource’s Capacity Supply Obligation for any future Capacity Commitment Periods and the resource’s right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource’s qualified capacity for participation in the Forward Capacity Market. Upon Commission ruling, the Project Sponsor 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’s Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO’s right to revoke that permission and to file with the Commission to terminate the resource’s Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

III.13.3.5. **Termination of Interconnection Agreement.**

If the ISO files with the Commission to terminate a resource’s Capacity Supply Obligation as described in Section III.13.3.4(c), the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. **Withdrawal from Critical Path Schedule Monitoring.**

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4.
III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting internal and external transmission limits and regional and local sourcing requirements updated using a methodology that is consistent with the Forward Capacity Auction) 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.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions, except Real-Time Emergency Generation Resources which may only submit demand bids. In accordance with Section III.A.9.2 of Appendix A of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource’s Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. 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. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will 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.13.4.2.

III.13.4.2.1. **Supply Offers.**
Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Non-Price Retirement Request or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. **Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.**
For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. **Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.**

III.13.4.2.1.2.1. **First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.**

III.13.4.2.1.2.1.1. **Generating Capacity Resources Other than Intermittent Power Resources.**

III.13.4.2.1.2.1.1.1. **Summer ARA Qualified Capacity.**
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power
Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource’s summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Qualification Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

**III.13.4.2.1.2.1.2. Winter ARA Qualified Capacity.**

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource’s winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Qualification Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.
(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.1.2.2. Winter ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.
(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.4. Demand Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.
III.13.4.2.1.2.1.4.2.  Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a)   For capacity that has achieved Commercial Operation, the resource’s most recently-determined winter Qualified Capacity.

(b)   Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.  Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1.  Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a)   For capacity that has achieved Commercial Operation, the resource’s summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b)   Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which
the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

### III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

### III.13.4.2.1.2.2.2. Intermittent Power Resources.

#### III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction
for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Adjustment for Certain Intermittent Power Resources and Intermittent Settlement Only Resources.
For an Intermittent Power Resource or an Intermittent Settlement Only Resource that was not part of an offer composed of separate resources and that has a winter Capacity Supply Obligation that was adjusted as described in Section III.13.2.7.6, if the difference between the resource’s winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction is greater
than the difference between the resource’s summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction, then the resource’s winter Capacity Supply Obligation shall be reduced such that the difference between the resource’s winter Capacity Supply Obligation and its Winter ARA Qualified Capacity for the third annual reconfiguration auction equals the difference between the resource’s summer Capacity Supply Obligation and Summer ARA Qualified Capacity for the third annual reconfiguration auction. For settlement purposes, any such reduction in Capacity Supply Obligation shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.4.1.2.2.3.  Import Capacity Resources.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import.

III.13.4.1.2.2.4.  Demand Resources.

III.13.4.1.2.2.4.1.  Summer ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a)  For capacity that has achieved Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value (or equivalent value as applicable to Demand Resources) in effect after the most recently completed summer period.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which
the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value (or equivalent value as applicable to Demand Resources) in effect after the most recently completed winter period.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource’s Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource’s Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10
Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a month be for an amount of capacity greater than the difference between the resource’s Capacity Supply Obligation for the month and the resource’s lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. 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 Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of
capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.4.2.1.5. ISO Review of Supply Offers.
Supply offers in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO’s reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall determine whether the capacity associated with supply offers that would otherwise clear in a reconfiguration auction will result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO’s reliability reviews will assess such offers, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security studies. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.
Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

(a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.
Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource’s capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.

All demand bids in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO’s reviews will consider the location and operating and rating limitations of resources associated with cleared demand bids to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall determine whether the capacity associated with demand bids that would otherwise clear in a reconfiguration auction is needed to avoid a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO’s reliability reviews will assess such bids, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security studies. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

ISO Participation in Reconfiguration Auctions.

The ISO shall not submit supply offers or demand bids in monthly reconfiguration auctions. The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to address year-to-year changes in the Installed Capacity Requirement (net of HQICCs) (including Local Sourcing Requirements and Maximum Capacity Limits for Capacity Zones for which price separation occurred in the Forward Capacity Auction for that Capacity Commitment Period) for the associated Capacity Commitment Period, to procure capacity not purchased in the Forward Capacity Auction as a result of Inadequate Supply, to procure any shortfall in capacity resulting from a resource’s achieving Commercial Operation at a level less than that resource’s Capacity Supply Obligation or other significant decreases in capacity, and to address any changes in interface transfer limits, as follows:
(a) The ISO shall submit supply offers and demand bids in annual reconfiguration auctions as appropriate to ensure that the applicable Installed Capacity Requirement (net of HQICCs), Local Sourcing Requirements, Maximum Capacity Limits, and interface transfer limits are respected. Where less capacity than needed is obligated, the ISO shall submit demand bids as appropriate to procure the additional needed capacity in each subsequent annual reconfiguration auction until the need is met. Where more capacity than needed is obligated, the ISO may in its discretion submit supply offers in subsequent annual reconfiguration auctions to release the excess capacity, but in any case the ISO shall be required to submit supply offers as appropriate in the third annual reconfiguration auction for a Capacity Commitment Period to release the excess capacity. No later than 10 Business Days prior to the start of each annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(b) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price.

(c) Any supply offer submitted by the ISO in an annual reconfiguration auction shall be in the form of a supply curve having the following characteristics:

(i) at prices equal to or greater than 0.75 times the Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), from the Forward Capacity Auction for the Capacity Commitment Period covered by the annual reconfiguration auction, the ISO shall offer the full amount of the surplus;

(ii) at prices between 0.75 times such Capacity Clearing Price and 0.25 times such Capacity Clearing Price, the amount of the surplus offered by the ISO shall decrease linearly (for example, at 0.5 times such Capacity Clearing Price, the ISO shall offer half of the amount of the surplus); and

(iii) At prices equal to or below 0.25 times such Capacity Clearing Price, the ISO shall offer no capacity.

(d) For purposes of this Section III.13.4.3, the Forward Capacity Auction Starting Price shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same
Capacity Commitment Period addressed by the reconfiguration auction, as determined pursuant to Section III.13.2.4.

(e) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not subject to the requirements and limitations described in Section III.13.4.2.

(f) Supply offers and demand bids submitted by the ISO in annual reconfiguration auctions are not associated with a resource.

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.
All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.2.1.1.

III.13.4.5. Annual Reconfiguration Auctions.
Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.
Except for the first five Capacity Commitment Periods, the first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period. There shall be no first annual reconfiguration auction for the first five Capacity Commitment Periods. The table below illustrates the annual reconfiguration auction timing provisions stated above, providing the schedule of annual reconfiguration auctions for the first eight Capacity Commitment Periods.
<table>
<thead>
<tr>
<th>First Annual Reconfiguration Auction</th>
<th>Second Annual Reconfiguration</th>
<th>Third Annual Reconfiguration</th>
<th>Capacity Commitment Period Begins</th>
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</tr>
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<td>March 2017</td>
<td>June 1, 2017</td>
</tr>
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### III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

### III.13.4.6. [Reserved.]

### III.13.4.7. 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.

### III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource’s Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource’s Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.
III.13.5. **Bilateral Contracts in the Forward Capacity Market.**

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. **Capacity Supply Obligation Bilaterals.**

A resource having a Capacity Supply Obligation seeking to shed that obligation (“Capacity Transferring Resource”) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (“Capacity Supply Obligation Bilateral”), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (“Capacity Acquiring Resource”), subject to the following limitations:

(a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.
(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) The Capacity Transferring Resource and the Capacity Acquiring Resource that are parties to a Capacity Supply Obligation Bilateral must be located in the same Capacity Zone, or the path from the Capacity Transferring Resource to the Capacity Acquiring Resource must flow across adjacent Capacity Zones in the direction of the modeled interface constraint(s), as such Capacity Zones and interface constraints are defined following the Forward Capacity Auction conducted for the Capacity Commitment Period to which the transferred Capacity Supply Obligation applies.

(g) If the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA 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 FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.
III.13.5.1.1.1. Timing.
The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating Procedures. The ISO will issue a submission schedule for annual Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. Monthly Capacity Supply Obligation Bilaterals may only be submitted and confirmed after the results of the third annual reconfiguration auction have been issued (except as described in Section III.13.4.2.1.3(c)) and prior to the closing of the monthly Capacity Supply Obligation Bilateral window, which will occur prior to the monthly reconfiguration auction. ISO New England will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO during the same submittal window and no later than the same deadline that applies to submission of the Capacity Supply Obligation Bilateral.

III.13.5.1.1.2. Application.
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, 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.13.5.1.1.3. 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 provisions of this Section III.13.5.1 are not met.

(b) Each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and
local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO’s review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO’s reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security studies. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource. The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting 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.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.
III.13.5.2. **Capacity Load Obligations Bilaterals.**

A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). 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.13.5.2.1. **Process for Approval of Capacity Load Obligation Bilaterals.**

III.13.5.2.1.1. **Timing.**

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 settlement of payments and charges associated with the Forward 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 pm on the second Business Day after the end 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.13.5.2.1.2. **Application.**

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.13.5.2.1.3. 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 II.13.5.2 are not met.

III.13.5.2.1.4. 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 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.

III.13.5.3. Supplemental Availability Capacity Performance Bilaterals.
A resource’s Capacity Performance Score availability score during a Capacity Scarcity Condition Shortage Event may be adjusted supplemented by entering into a Supplemental Availability Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.
If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition. Demand Response Capacity Resources and Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. A Demand Response Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource’s Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.
III.13.5.3.1.2. Designation.
The designation of a Supplemental Capacity Resource must be made by the resource’s Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.
The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.
Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for Generating Capacity Resources and as described in Sections III.13.6.1.5.1. and III.13.6.1.5.2. for Demand Response Capacity Resources for the entire term indicated in the designation described in Section III.13.5.3.1.2.

III.13.5.3.2. Submission of Supplemental Availability Capacity Performance Bilaterals.
The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score, available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource or Demand Response Capacity Resource having a Capacity Supply Obligation during that Shortage Event (“Supplemented Capacity Resource”). No other Market Participant...
may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the
Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no-
case may a Supplemental Capacity Resource located in an export-constrained Capacity Zone provide
supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different
Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the
Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For
purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established-
pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with
respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental-
Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental-
capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity
Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.
A Supplemental Availability Capacity Performance Bilateral must be submitted in accordance with
resettlement provisions as described in ISO New England Manuals. However, to be included in the initial
settlement of payments and charges associated with the Forward Capacity Market for the month
associated with the Supplemental Availability Capacity Performance Bilateral, a Supplemental-
Availability Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the
second Business Day after the end of that month, or at such later deadline as specified by the ISO upon
notice to Market Participants (though a Supplemental Availability Capacity Performance Bilateral may be
revised by the parties to the transaction throughout the resettlement process). A Supplemental-
Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity-
Resource no later than the same deadline that applies to submission of the Supplemental Availability-
Bilateral.

III.13.5.3.2.2. Application.
The submission of a Supplemental Availability Capacity Performance Bilateral to the ISO shall include
the following: (i) the resource identification number for the resource transferring its Capacity
Performance Score Supplemental Capacity Resource; (ii) the resource identification number for the
resource receiving the Capacity Performance Score Supplemented Capacity Resource; (iii) the MW
amount of Capacity Performance Score capacity being transferred assigned from the Supplemental
Capacity Resource to the Supplemented Capacity Resource; (iv) the specific five-minute interval or
intervals for which the Capacity Performance Bilateral applies, the term of the transaction, which shall be
in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one-
calendar month.

III.13.5.3.2.3. ISO Review.
The ISO shall review the information provided in submission of the Supplemental AvailabilityCapacity
Performance Bilateral, and shall reject the Supplemental AvailabilityCapacity Performance Bilateral if
any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a
Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity
Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and
the MW amount of capacity being assigned from the Supplemental Capacity Resource is (a) less than or
equal to the difference between the Generating Capacity Resource’s Economic Maximum Limit as
submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource’s
Capacity Supply Obligation or (b) less than or equal to the difference between (the greater of the Demand
Response Capacity Resource’s Real-Time Demand Reduction Obligation plus Net Supply or the lesser of
((the Demand Response Capacity Resource’s Demand Response Baseline as adjusted pursuant to Section
III.8B.5, plus the Economic Maximum Limit for any associated available Net Supply Generator Assets),
the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared
by the Lead Market Participant plus the Economic Maximum Limit of associated Net Supply Generator
Assets))), adjusted for average avoided peak transmission and distribution losses as addressed in Section
III.13.7.1.5.10, and the Supplemental Capacity Resource’s Capacity Supply Obligation; or (ii) the
Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of
capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference
between the sum of the Supplemental Capacity Resource’s Real-Time Reserve Designations of TMNSR
and TMOR and the Supplemental Capacity Resource’s Capacity Supply Obligation.

III.13.5.3.32.4. Effect of Supplemental AvailabilityCapacity Performance Bilateral.
A Supplemental AvailabilityCapacity Performance Bilateral does not affect in any way either party’s
Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a
Supplemental AvailabilityCapacity Performance Bilateral is to modify the Capacity Performance Scores
of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity
Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section
III.13.7.2 Supplemented Capacity Resource’s availability score as described in Section III.13.7.1.1.4.
III.13.6. **Rights and Obligations.**

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. **Resources with Capacity Supply Obligations.**

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. **Generating Capacity Resources.**

III.13.6.1.1.1. **Energy Market Offer Requirements.**

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource’s notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) 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.

III.13.6.1.1.2. **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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. **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;

(c) 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 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.13.6.1.2. Import Capacity Resources.


A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource.

A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source-interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven-
percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.


(bè) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.

(ce) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market. If a Market Participant does not link the transaction to the associated transmission reservation and NERC E-Tag in the Real-Time Energy Market for any hour during which the External Transaction would otherwise have been economically and reliably scheduled in the Real-Time Energy Market, the associated Import Capacity Resource shall be treated as having not delivered energy for the hour despite ISO requested dispatch under Section III.13.7.1.2 and III.13.7.2.7.2. A Market Participant submitting any other External Transaction to the Real-Time Energy Market must comply with the requirements in Section III.1.10.7(e) with respect to linking the transaction to the associated transmission reservation and NERC E-Tag.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.
Import Capacity Resources are subject to the following additional requirements:

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;
(b) resource backed Import Capacity Resources shall be subject to the outage requirements as
backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-
scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO
New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity
Resource.

III.13.6.1.3. Intermittent Power Resources.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are
required to submit offers 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.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures
and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement
Only Resources.
III.13.6.1.4.1. **Energy Market Offer Requirements.**


III.13.6.1.4.2. **Additional Requirements for Settlement Only Resources.**

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only 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;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. **Demand Resources.**

III.13.6.1.5.1. **Energy Market Offer Requirements.**

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

A Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers through its Demand Response Resources and submit Supply Offers of any associated Net Supply Generator Assets, into both the Day-Ahead Energy Market and Real-Time Energy Market through its Demand Response Resources and associated Net Supply Generator Assets. The sum of the Demand Reduction Offers and Supply Offers must be equal to or greater than the Demand Response Capacity Resource’s Capacity Supply Obligation whenever the Demand Response Resources and associated Net Supply Generator Assets are physically available. If the Net Supply Generator Asset is a Settlement Only Resource, then the Net Supply will not be represented in the offer for the Demand Response Resource. If the Demand Response Resources and associated Net Supply Generator Assets are
Physically available at a level less than the Demand Response Capacity Resource’s Capacity Supply Obligation, the sum of the Demand Reduction Offers and Supply Offers equal to that level 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 one of the following requirements:

(a) 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) the sum of the Demand Response Resource’s Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

Each Supply Offer for a Net Supply Generator Asset associated with a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:

(a) the sum of the Net Supply Generator Asset’s Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours.

(b) the sum of the Net Supply Generator Asset’s Minimum Run Time plus Minimum Down Time is less than or equal to 24 hours.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers and, if applicable, Supply Offers of associated Net Supply Generator Assets, submitted into the Day-Ahead Energy Market and Real-Time Energy Market for the portion of a resource having a Capacity Supply Obligation must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the 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 economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.
Demand Resources shall comply with the ISO’s measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;

(b) 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 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.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

(a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;

(b) Verifying the Commercial Operation of a Demand Resource; and

(c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

### III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

(a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.
(b) The results of an audit shall be adjusted to reflect any changes in the composition of the Demand Resource resulting from the unmapping of a demand asset from the resource subsequent to the performance of the audit.

(c) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.

(d) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

(e) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

(a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset and Net Supply Generator Asset that is mapped to each associated Demand Response Resource.

(b) The results of an audit shall be adjusted to reflect any changes in the composition of the Demand Response Resource resulting from the unmapping of a Demand Response Asset and Net Supply
Generator Asset from the Demand Response Resource subsequent to the performance of the audit.

(c) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section 8B.5, of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(d) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2017, the audit results for Demand Response Resources comprised of Demand Response Assets and associated Net Supply Generator Assets that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2017 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

(e) If one or more Demand Response Assets of a Demand Response Resource or associated Net Supply Generator Assets do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets or associated Net Supply Generator Assets toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset or associated Net Supply Generator Asset was available for dispatch by the ISO in that prior month, and if the Demand Response Asset or associated Net Supply Generator Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset or associated Net Supply Generator Asset was available for dispatch.
III.13.6.1.5.4.3. Seasonal DR Audits.
A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.
A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.
If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.
A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute notification time, may use the first 60 minute
period of the event after the 30 minute notification time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(c). A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource’s audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource’s Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.
A Demand Response Capacity Resource may elect to use performance associated with a Capacity Scarcity Condition Shortage Event as defined in Section III.13.7.1.1.1 or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4 that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets and associated Net Supply Generator Assets shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point (for the Demand Response Resource and its associated Net Supply Generator Assets) over the audit duration by proportionally reducing each associated Demand Response Asset’s and Net Supply Generator Asset’s audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the resource’s Audited Demand Reduction.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource
Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) Demand Resource Commercial Operation Audits not performed prior to the commencement of the Capacity Commitment Period must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

(1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;

(2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource’s actual capability. Such criteria include, but are not limited to:

(a) A pattern of submitting to the ISO a level of available interruption that is less than the resource’s Demand Reduction Value or Audited Demand Reduction during the same time period;
(b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource’s Demand Reduction Value or Audited Demand Reduction; or

(c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset and associated Net Supply Generator Asset. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset and associated Net Supply Generator Asset to verify that the reported 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 measures in the demand asset or Demand Response Asset and associated Net Supply Generator Asset. 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 Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.
(a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.

(b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.

(c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.

(d) For Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Demand Response Capacity Resource will be based on the sum of the average load reductions or average Net Supply demonstrated during the audit by each Demand Response Asset and associated Net Supply Generator Asset associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource’s Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction plus the sum of the Economic Maximum Limits of any associated available Net Supply Generator Assets minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of the Net Supply Generator Asset is reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.1.5.4.7. Requesting and Performing an Audit.

(a) Seasonal DR Audits and Demand Resource Commercial Operation Audits will be performed following the request of the Market Participant. Audits will be performed within 20 Business Days of the date requested by the Market Participant. The date and time of the audit will be unannounced. An audit
request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

(d) Seasonal DR Audits may be performed on different dates and at different times for Demand Response Resources associated with a Demand Response Capacity Resource if the Demand Response Resources have different offer parameters. In addition, the ISO will only schedule Demand Resource Commercial Operation Audits of a Demand Response Resource with Demand Response Assets that do not have an Audited Demand Reduction value.

(e) New Demand Response Asset Audits will be performed following the request of the Market Participant. The request for a New Demand Response Asset Audit by the Market Participant shall be made during the last seven days of the month. The audit will be performed on Business Days during the month following the date of the request by the Market Participant. The date and time of the audit will be unannounced. An audit request may be denied by the ISO, and an audit may be rescheduled, if its performance will jeopardize the reliable operation of the electrical system.

III.13.6.1.5.4.8. New Demand Response Asset Audits

A Market Participant may request a New Demand Response Asset Audit for all New Demand Response Assets that are mapped to a Demand Resource. The results of a New Demand Response Asset Audit may be used:

- In calculating the Seasonal DR Audit value for the Demand Resource to which the asset is mapped until the next Seasonal DR Audit for the full Demand Resource is conducted;
- For determination regarding termination under Section III.13.3.4(c); and
- In the monthly calculation of a Demand Resource’s Demand Reduction Value pursuant to Section III.13.7.1.5.7 and Section III.13.7.1.5.8.

III.13.6.1.5.4.8.1. General Auditing Requirements for New Demand Response Assets.
(a) A New Demand Response Asset Audit will be conducted by simultaneously evaluating the performance of each New Demand Response Asset that is mapped to that Demand Resource.

(b) A New Demand Response Asset Audit is valid beginning with the month in which the audit is performed, and remains valid until the next Seasonal DR Audit is performed for a like season. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the month following the audit. Audit results shall not be used in the calculation of a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.

III.13.6.1.5.5. Reporting of Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO a two-day forecast of each Demand Resource’s Forecast Hourly Demand Reduction for each Operating Day. The Market Participant shall update its forecast, in accordance with the ISO New England Manuals and Operating Procedures, to reflect its estimate of each Demand Resource’s Forecast Hourly Demand Reduction.

III.13.6.1.5.6. Reporting of Monthly Maximum Forecast Hourly Demand Reduction.

A Market Participant with Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources shall, in accordance with the ISO New England Manuals and Operating Procedures, submit to the ISO each month a forecast of each resource’s monthly maximum Forecast Hourly Demand Reduction for each of the next 12 months.

III.13.6.2. 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.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.


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.

A Generating Capacity Resource having no 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, must Self-Schedule in order to participate 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.13.6.2.1.2. 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 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.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources 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.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.
Settlement Only Resources 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;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.
III.13.6.2.5.1. **Energy Market Offer Requirements.**


For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market from such Demand Response Resources, the sum of the Demand Response Resource’s Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

For Supply Offers made into the Day-Ahead Energy Market and Real-Time Energy Market from such Net Supply Generator Assets, the sum of the Minimum Run Time plus the Minimum Down Time must also be less than or equal to 24 hours.

III.13.6.2.5.1.1. **Day-Ahead Energy Market Participation.**

A Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer or, for any associated Net Supply Generator Asset, a Supply Offer, into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer or Supply Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer or Supply Offer, up to the Maximum Reduction or 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 Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. **Real-Time Energy Market Participation.**

A Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response 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 or, for any associated Net Supply Generator Assets, a Supply 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.13.6.2.5.2. Additional Requirements for Demand Response Capacity Resources Having No Capacity Supply Obligation.**

Demand Response Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and 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. Demand Response Capacity Resources having no 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.13.6.3. 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.13.6.3 and the ISO New England Manuals. Intermittent Power Resources, Settlement Only Resources, and Demand 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.

**III.13.6.4. ISO Requests for Energy.**

The ISO may request that a Demand Response Capacity Resource or Generating 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 Section III.13 of this Tariff by such a request to provide energy from that capacity, and shall not be subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that capacity.
capacity that is not subject to a Capacity Supply Obligation. 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.13.6.4.1. Real-Time High Operating Limit.
For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.
Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3. During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

#### III.13.7.1. Capacity Base Payments, Performance Measures

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

#### III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations, Generating Capacity Resources

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

1. **[Text below moved from old Section III.13.7.2.1.1, then redlined.]**
(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

[This is old Section III.13.7.1.1 being deleted] During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any Shortage Events during the month.
III.13.7.1.22.7.1.1. Peak Energy Rents. [Text below moved from old Section III.13.7.2.7.1.1, then redlined.]

Capacity Base Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.22.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER} (\$/kW) = [(\text{LMP} - \text{Strike Price})] \times [\text{Scaling Factor}] \times [\text{Availability Factor}]$$

Where:

- Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

- Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

- Availability Factor = 0.95²
(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource’s PER deduction for an Obligation Month be less than zero or greater than the product of the resource’s Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price/Capacity Base Payment for the Obligation Month follows:

\[ \text{PER Adjustment} = \text{the minimum of: (i) the PER cap or (ii) the Average Monthly PER} \times \text{PER Capacity Supply Obligation}. \]
Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.

(b) In an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone.

(c) An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by
less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.
For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource’s hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource’s Shortage Event Availability Score.

III.13.7.1.1.2 Hourly Availability Scores.
The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource’s availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource’s available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource’s Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3 Hourly Available MW.
A resource’s available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource’s available MW in an hour exceed that resource’s CNR Capability (reduced by the hourly-integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.
(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource’s metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource’s available MW in an hour shall not be reduced as a result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource’s available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by...
the first day of the Obligation Month, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4 Availability Adjustments

(a) A resource’s hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource’s Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource’s hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO’s annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource’s hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or
January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource’s performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.
(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource’s available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource’s metered output for the hour.
III.13.7.1.4.2. Intermittent Settlement Only Resources.
The performance measure for Intermittent Settlement Only Resources will be included in the
determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and
Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.
The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction
Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed
Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO
for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the
Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and
distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the
Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand
Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity
Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the
month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided
peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the
Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand
Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement
divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average
avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through
Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply
Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.
For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment
Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply
Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period
beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its
Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the
product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the
Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its...
Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer was cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset’s monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer’s load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly-
Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.
Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.
III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

(a) 

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand-
Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the
Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a-
Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.7.1.5.8.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. **Winter Seasonal Demand Reduction Value.**
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. **Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.**
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation.
and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.


An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.


Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity.
Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the
Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand-
Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource-
Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity-
Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the
Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to
apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its
Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply-
Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to
apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity-
Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward-
Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.
The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be
measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity-
Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the
manner described in Section III.13.7.1.1.1A and III.13.7.1.1.2, respectively (with the hourly availability-
score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce
demand, availability for Demand Response Capacity Resources would be adjusted for average avoided-
peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section
III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for
Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and
distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.
A Demand Response Capacity Resource’s available MW in each hour that contains any portion of a
Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as-
follows, provided, that in no case shall a Demand Response Capacity Resource’s available MW in an-
hour exceed that resource’s Qualified Capacity from the Forward Capacity Auction for the current-
Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when
the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted
pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and
Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail
Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply Generator Asset, shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(a) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instructions where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than (the Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (the resource’s Real-Time Demand Reduction Obligation plus the Net Supply for any associated available Net Supply Generator Assets) and the lesser of (the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Economic Maximum Limit for any associated available Net Supply Generator Assets), the resource’s Hourly Adjusted Audited Demand Reduction, or (the resource’s Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant).

(b) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instruction where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is equal to Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets or (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets) or total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than the Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation plus any associated Net Supply is less than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available
MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply for the hour.

(d) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets that have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the lesser of the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) of thirty minutes or less, the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, and Actual Load) plus the sum of the Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead market Participant) or Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, the resource’s Actual Load plus Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant or the resource’s Hourly Adjusted Audited Demand Reduction time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.
For a Demand Response Resource that (i) is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction:
A Demand Response Resource’s Adjusted Audited Demand Reduction shall be determined as follows:
For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5 of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction set equal to the resource’s Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{\text{(the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}}{\text{(the Offered Full Reduction Time adjusted for the Audited Demand Reduction))}} \times \min\left(\text{Audited Demand Reduction}, \text{(Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets)}\right)
\]

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction-
plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{(\text{the Offered Full Reduction Time adjusted for the Audited Demand Reduction})}{(\text{the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets)))} \times \text{lesser of (the Audited Demand Reduction or (Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}
\]

### III.13.7.1.5.10.2 Availability Adjustments

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Capacity Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource’s hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced reduction or scheduled reduction.

   (i) A forced reduction can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the
Demand Response Asset that is subject to the forced reduction. The forced reduction can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource.

(ii) A scheduled reduction must be submitted to the ISO at least 15 days ahead of the start of the reduction to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy-consuming equipment. The scheduled reduction cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource. Scheduled reductions must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus Economic Maximum Limit for any associated available Net Supply Generator Assets and Audited Demand Reduction adjusted down by the greater of (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets), or (Real-Time Demand Reduction Obligation plus Net Supply for any associated Net Supply Generator Assets). For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that as not received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Actual Load plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant), and the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any-
associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market-
Participant).

III.13.7.1.6. ______ Self-Supplied FCA Resources.
Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their-
resource type.

III.13.7.2. ______ Payments and Charges to Resources.
Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges-
in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed-
in Section III.13.7.2.7.

III.13.7.2.1. ______ Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments. [Moved to new Section III.13.7.1.1, then
redlined.]
Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources-
designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month-
pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a-
Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments-
in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) ______ Forward Capacity Auction. For a resource whose offer has cleared in a Forward Capacity-
Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case-
described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its-
audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England-
Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for-
resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in-
the manner described below (the “FCA Payment”). For a resource that has elected to have the Capacity-
Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment-
Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed-
using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the-
year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment-
(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

### III.13.7.2.2. Import Capacity.
Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

### III.13.7.1.32.2.A. Export Capacity.
If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

**Charge Amount to Resource Exporting** = \([\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}] \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid}\)

**Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located** = \([\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}] \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid}\)
Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.53.1.

III.13.7.2.3. Intermittent Power Resources

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.1.42.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

### III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources
A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

### III.13.7.1.52.5.4. Energy Settlement for Real-Time Emergency Generation Resources
A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.1.52.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

### III.13.7.1.52.5.4.1 Adjustment for Net Supply Generator Assets.
For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the
output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

**III.13.7.2.6. Self-Supplied FCA Resources.**

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource-designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

**III.13.7.2.7. Adjustments to Monthly Capacity Payments.**

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

**III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.**

**III.13.7.2.7.1.1. Peak Energy Rents.** [Moved to new Section III.13.7.1.2, then redlined.]

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

**III.13.7.2.7.1.1.1. Hourly PER Calculations.**

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike-price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER}($/kW) = \left[ (\text{LMP} - \text{Strike Price}) \times \text{Scaling Factor} \times \text{Availability Factor} \right]
\]

Where:
Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b)——PER Proxy Unit characteristics shall be as follows:

(i)——The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra-low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(ii)——The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run-time constraints.

(iii)——The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2.——Monthly PER Application.

(a)——The Hourly PER shall be summed for each calendar month to determine the total PER for that month (“Monthly PER”). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12-
months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

\[
\text{PER Adjustment} = \min (\text{i}) \text{the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.}
\]

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.
Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event.
(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

\[
\text{Penalty} = \left[ \text{Resource’s Annualized FCA Payment} \right] \times \text{PF} \times \left[ 1 - \text{Shortage Event Availability Score} \right]
\]

\[
\text{Where:}
\]

Annualized FCA Payment — the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource’s Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

\[
\text{PF} = 0.05 \text{ for Shortage Events of } 5 \text{ hours or less. PF is increased by } \frac{0.01}{\text{hour}} \text{ for each additional hour above } 5 \text{ hours.}
\]

III.13.7.2.7.1.3 Availability Penalty Caps

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) Per Day. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource’s Annualized FCA Payment for that Capacity Commitment Period.

(b) Per Month. The sum of a resource’s penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.
(c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

**III.13.7.2.7.1.4. Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.**

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

**III.13.7.2.7.2. Import Capacity.**

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

**III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.**

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.
(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource’s Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO’s annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant’s total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.
a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

e) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.
Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.
Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.
For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.
With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price.
in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.2.7.5.3 Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource’s Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particular Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time-
Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources. [Moved to new Section III.13.7.1.2.]

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.2. Capacity Performance Payments.

III.13.7.2.1. Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each
as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition.

(a) A Generating Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the resource’s output during the interval plus the resource’s Real-Time Reserve Designation (including any regulation capability available but not used for energy) applicable to the particular Capacity Scarcity Condition for the hour in which the Capacity Shortage Condition occurred; provided, however, that if the resource’s output was limited during the Capacity Scarcity Condition as a result of a binding transmission constraint, then the resource’s Actual Capacity Provided may not be greater than the resource’s Desired Dispatch Point 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 Shortage Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Shortage Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource associated with a single interface, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource On-Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource On-Peak Hours and shall be zero.
(d) A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource Seasonal Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource Seasonal Peak Hours and shall be zero.

(e) A Real-Time Emergency Generation Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Shortage Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Shortage Condition occurred; and shall be multiplied by 1.08.

(f) A Demand Response Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource’s Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

### III.13.7.2.3 Capacity Balancing Ratio

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

\[
\frac{(\text{Load} + \text{Reserve Requirement})}{\text{Total Capacity Supply Obligation}}
\]
(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves 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:

\[ \text{Load} = \text{the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.} \]

\[ \text{Reserve Requirement} = \text{the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves.} \]

\[ \text{Total Capacity Supply Obligation} = \text{the total amount of Capacity Supply Obligations in the New England Control Area during the interval.} \]

(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning 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:

\[ \text{Load} = \text{the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.} \]

\[ \text{Reserve Requirement} = \text{the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval.} \]

\[ \text{Total Capacity Supply Obligation} = \text{the total amount of Capacity Supply Obligations in the New England Control Area during the interval.} \]

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves 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 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).

Reserve Requirement = the local Thirty-Minute Operating 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.

(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 local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

(ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.
Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative.
III.13.7.2.5 Capacity Performance Payment Rate.
For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The Capacity Performance Payment Rate is subject to review by the ISO in the stakeholder process no less often than once every three years. The ISO shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.
For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Payment for an interval shall equal the resource’s Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.2.7 Exceptions Due to a Transmission Outage.
A Generating Capacity Resource’s Capacity Performance Score shall be set to zero if that resource’s inability to deliver energy or reserves during a Capacity Scarcity Condition is due to that resource not being committed as a result of a transmission outage or transmission derating.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.
Each resource’s Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource’s Capacity Base Payment for the Obligation Month plus the sum of the resource’s Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below. provided, however, that

III.13.7.3.1 Monthly Stop-Loss.
If the sum of the resource’s Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource’s Capacity Supply Obligation in
any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from
the resource’s Capacity Base Payment for the Obligation Month will be limited to an amount equal to:

(i) the product of Two-thirds of the applicable Forward Capacity Auction Starting Price
multiplied by the resource’s Capacity Supply Obligation for the Obligation Month,
where the Capacity Clearing Price is at or below $4.00/kW-month;
(ii) two point five (2.5) times the Capacity Clearing Price multiplied by the resource’s
Capacity Supply Obligation for the Obligation Month, where the Capacity Clearing
Price is between $4.00/kW-month and $6.00/kW-month; or
(iii) the product of the applicable Forward Capacity Auction Starting Price multiplied by the
resource’s Capacity Supply Obligation for the Obligation Month, where the Capacity
Clearing Price is at or above $6.00/kW-month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a
Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections
III.13.1.2.2.4 and III.13.1.4.2.2.5, the amount subtracted from the resource’s Capacity Base Payment for
the Obligation Month will be limited to an amount as described above in (i), (ii), (ii) but the equal to the
product of the applicable Capacity Clearing Price will be (indexed for inflation) multiplied by the
resource’s Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

\[
\text{MaxCSO} \times [3 \text{ months} \times (\text{FCAcp} – \text{FCAsp}) – (12 \text{ months} \times \text{FCAcp})]
\]

Where:

\[
\text{MaxCSO} = \text{the resource’s highest monthly Capacity Supply Obligation in the Capacity}
\text{Commitment Period to date.}
\]

\[
\text{FCAcp} = \text{the Capacity Clearing Price for the relevant Forward Capacity Auction.}
\]
FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource’s cumulative Capacity Performance Payments as the sum of the resource’s Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource’s Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource’s Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource’s Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource’s cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.3.34 Opt-Out for Resources Electing Multiple-Year Treatment.
Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline, opt out of the remaining years of the resource’s multiple-year election. A decision to so opt out shall be irrevocable. A resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.7.4 Allocation of Deficient or Excess Monthly Capacity Performance Payments.
For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 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 Monthly 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.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Monthly 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 in proportion to each resource’s Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

III.13.7.53. Charges to Market Participants with Capacity Load Obligations.
A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section 13.7.2.1.27.1.2, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.32.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.
III.13.7.35.1. **Calculation of Capacity Requirement and Capacity Load Obligation.**

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity’s Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone’s Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity’s annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Commitment Period from the calendar year prior to the start of the Capacity Commitment Period.

A load serving entity’s Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.
III.13.7.53.1.1. **HQICC Used in the Calculation of Capacity Requirements.**

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.53.1.2. **Charges Associated with Self-Supplied FCA Resources.**

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.53.1.3. **Charges Associated with Dispatchable Asset Related Demands.**

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity’s Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.53.2. **Excess Revenues.**

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.53.3. **Capacity Transfer Rights.**

III.13.7.53.3.1. **Definition and Payments to Holders of Capacity Transfer Rights.**

The ISO shall create Capacity Transfer Rights (“CTRs”) for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total
CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone’s Net Regional Clearing Price and absolute value of each Capacity Zone’s Capacity Load Obligations, as calculated in Section III.13.7.53.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone’s portion of the CTR fund. The
balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.


For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.53.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) Connecticut Import Interface. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) NEMA/Boston Import Interface. Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(c) 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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.53.3. Allocations of CTRs Resulting From Revised Capacity Zones.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.
(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.53.3.4. **Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.53.5. [Reserved.]

III.13.7.53.6. **Specifically Allocated CTRs for Pool Planned Units.**

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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.
<table>
<thead>
<tr>
<th></th>
<th>Millstone 3</th>
<th>Seabrook</th>
<th>Stonybrook GT 1A</th>
<th>Stonybrook GT 1B</th>
<th>Stonybrook GT 1C</th>
<th>Stonybrook 2A</th>
<th>Stonybrook 2B</th>
<th>Wyman 4</th>
<th>Summer (MW)</th>
<th>Winter (MW)</th>
</tr>
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<tbody>
<tr>
<td>Nominal Summer (MW)</td>
<td>1155.001</td>
<td>1244.275</td>
<td>104.000</td>
<td>100.000</td>
<td>104.000</td>
<td>67.400</td>
<td>65.300</td>
<td>586.725</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal Winter (MW)</td>
<td>1155.481</td>
<td>1244.275</td>
<td>119.000</td>
<td>116.000</td>
<td>119.000</td>
<td>87.400</td>
<td>85.300</td>
<td>608.575</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Danvers</td>
<td>0.2627%</td>
<td>1.1124%</td>
<td>8.4569%</td>
<td>8.4569%</td>
<td>8.4569%</td>
<td>11.5551%</td>
<td>11.5551%</td>
<td>0.0000%</td>
<td>58.26</td>
<td>63.73</td>
</tr>
<tr>
<td>Georgetown</td>
<td>0.0208%</td>
<td>0.0956%</td>
<td>0.7356%</td>
<td>0.7356%</td>
<td>0.7356%</td>
<td>1.0144%</td>
<td>1.0144%</td>
<td>0.0000%</td>
<td>5.04</td>
<td>5.55</td>
</tr>
<tr>
<td>Ipswich</td>
<td>0.0608%</td>
<td>0.1066%</td>
<td>0.2934%</td>
<td>0.2934%</td>
<td>0.2934%</td>
<td>0.0000%</td>
<td>0.0000%</td>
<td>0.0000%</td>
<td>2.93</td>
<td>2.37</td>
</tr>
<tr>
<td>Marblehead</td>
<td>0.1544%</td>
<td>0.1351%</td>
<td>2.6840%</td>
<td>2.6840%</td>
<td>2.6840%</td>
<td>1.5980%</td>
<td>1.5980%</td>
<td>0.2793%</td>
<td>15.49</td>
<td>15.64</td>
</tr>
<tr>
<td>Middleton</td>
<td>0.0440%</td>
<td>0.3282%</td>
<td>0.8776%</td>
<td>0.8776%</td>
<td>0.8776%</td>
<td>1.8916%</td>
<td>1.8916%</td>
<td>0.1012%</td>
<td>10.40</td>
<td>11.07</td>
</tr>
<tr>
<td>Peabody</td>
<td>0.2969%</td>
<td>1.1300%</td>
<td>13.0520%</td>
<td>13.0520%</td>
<td>13.0520%</td>
<td>0.0000%</td>
<td>0.0000%</td>
<td>0.0000%</td>
<td>57.69</td>
<td>60.26</td>
</tr>
<tr>
<td>Reading</td>
<td>0.4041%</td>
<td>0.6351%</td>
<td>14.4530%</td>
<td>14.4530%</td>
<td>14.4530%</td>
<td>19.5163%</td>
<td>19.5163%</td>
<td>0.0000%</td>
<td>82.98</td>
<td>92.77</td>
</tr>
<tr>
<td>Wakefield</td>
<td>0.2055%</td>
<td>0.3870%</td>
<td>3.9929%</td>
<td>3.9929%</td>
<td>3.9929%</td>
<td>6.3791%</td>
<td>6.3791%</td>
<td>0.4398%</td>
<td>30.53</td>
<td>32.64</td>
</tr>
</tbody>
</table>
This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.53.4.  Forward Capacity Market Net Charge Amount.
The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.
III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward 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;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor’s determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor’s
determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource’s long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor’s determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO’s submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO’s submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO’s submission of the informational filing, the Commission does issue an order modifying one or more of the ISO’s determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices
resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO’s filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.
III.13.8.3. [Reserved.]
III.13.8.4. [Reserved.]
MMWEC modifications to FCMPI

Gary Will

Massachusetts Municipal Wholesale Electric Company
Eliminate non-performance penalties when due to a loss of transmission

When the generation resource is ready and able to provide energy but cannot:

• loss of production is beyond generators control

• there is no basis to penalize the resource
  – the penalty cannot serve to encourage the generation resource owner to make different arrangements

• the generator already suffers lost opportunity
  – pointless and presents a risk that cannot be hedged
Eliminate non-performance penalties when on a planned outage.

A power generating plant may not be able to deliver energy or reserves when on a planned outage:

• ISO New England Operating Procedure No. 5
  – Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5)

• already accounted for in establishing ICR
Elimination of provisions of FCMPI from applying to the NYPA contracts

• Import Capacity Resources associated with the NYPA contracts listed in Section III.13.1.3.3(c)
• power deliveries to New England from NYPA’s Niagara and St. Lawrence hydro-projects
• Federal Preference Power
  – mandated by federal law
  – required under 50-year, FERC-approved licenses
• predate both the FCM and SMD
NYPA contracts (cont.)

Power flowing from NYPA contracts to New England entities

<table>
<thead>
<tr>
<th>Entity</th>
<th>MW Contract</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>13.2</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>53.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>2.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Vermont</td>
<td>15.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Total</td>
<td>84.1</td>
<td></td>
</tr>
</tbody>
</table>

NYPA imports are unique
- firm capacity
- almost perfectly-available due to the reliability of the underlying hydroelectric facilities
- scheduled power at multiple interconnection points
- NYPA contractual replacement-energy obligations
NYPA contracts (cont.)

FERC’s Jan. 8, 2008 Forward Capacity Market Rules Order

• different treatment of these contracts for FCM purposes is not unduly discriminatory
  – ISO urged for different treatment and FERC agreed
  – special treatment under the FCM rules needed "in order to better recognize the rights of certain existing long-term import capacity contracts."
NYPA contracts (cont.)

“FCM Competitive Import Requirements”
• requires capacity importers to submit energy offers at competitive prices
• subject capacity importers to penalties for failing to comply with “FCM” participation requirements
• included an exemption for Existing Import Capacity Resources associated with Specific Long-Term Contracts
• accepted by FERC Order issued May 20, 2010,
  - In approving the revisions, the Commission stated that it “finds that the reformed penalty structure on the whole will provide a more meaningful incentive for capacity importers to deliver energy when they are requested to do so.”
Elimination of provisions of FCMPI from applying to Intermittent Resources

• Qualified Capacity is currently based on the median summer and winter reliability hours averaged over a five year period (Market Rule 1, Section 13.1.2.2.2.1 (a)-(d) and 13.1.2.2.2.2)
  – significantly reduction from nameplate rating
• Shortage Event hours added to the total reliability hours during the respective summer and winter periods
  – Serve as a Performance Incentive potentially reducing the capacity payments further
• ICR calculation and other practices and planning procedures already take into account the intermittent nature of these resources
III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed annually and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.
Questions?
III.13.7.2.7 Exception.

(a) Intermittent Power Resources shall be exempt from provisions set forth in this Section III.13.7.2.
MMWEC AMENDMENT #2
III.13.7. **Performance, Payments and Charges in the FCM.**

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3. During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

**III.13.7.2 Capacity Performance Payments.**

**III.13.7.2.1 Definition of Capacity Scarcity Condition.**

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

**III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.**
For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition.

(a) A Generating Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the resource’s output during the interval plus the resource’s Real-Time Reserve Designation (including any regulation capability available but not used for energy) applicable to the particular Capacity Scarcity Condition for the hour in which the Capacity Shortage Condition occurred; provided, however, that if the resource’s output was limited during the Capacity Scarcity Condition as a result of a binding transmission constraint, then the resource’s Actual Capacity Provided may not be greater than the resource’s Desired Dispatch Point 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 Shortage Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Shortage Condition occurred where a single Market Participant owns more than one Import Capacity Resource associated with a single interface, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource On-Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource On-Peak Hours and shall be zero.

(d) A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource Seasonal Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource Seasonal Peak Hours and shall be zero.
(e) A Real-Time Emergency Generation Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Shortage Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Shortage Condition occurred; and shall be multiplied by 1.08.

(f) A Demand Response Capacity Resource’s Actual Capacity Provided during a Capacity Shortage Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource’s Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exits, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

\[
\frac{(\text{Load} + \text{Reserve Requirement})}{\text{Total Capacity Supply Obligation}}
\]

(a) If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(b) If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning 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 reserve designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning 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.

(c) If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves 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 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).
Reserve Requirement = the local Thirty-Minute Operating 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.

(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 local Thirty-Minute Operating Reserves requirement and either the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c).

   (ii) In any Capacity Zone subject to both the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative.

III.13.7.2.5 Capacity Performance Payment Rate.
For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed annually and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

**III.13.7.2.6 Calculation of Capacity Performance Payments.**

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Payment for an interval shall equal the resource’s Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Rate for an interval may be positive or negative.

**III.13.7.2.7 Exceptions.**

(a) Existing Import Capacity Resources associated with the NYPA contracts listed in Section III.13.1.3.3(c) shall be exempt from provisions set forth in this Section III.13.7.2, provided that the associated transactions are self-scheduled and perform according to their contract terms.

(b) A resource’s Capacity Performance Score shall be set to zero if that resource’s inability to deliver energy or reserves during a Capacity Scarcity Condition is a Planned Outage that was scheduled and approved in accordance with ISO New England Operating Procedure No. 5 – Generation and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5).

(c) For internal New England Generators and Demand Response resources with a CSO, its Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver energy or reserves during that Capacity Scarcity Condition is due to an outage or de-rate of a Transmission Facility in the New England Control Area that is beyond the control of the resource.

(d) For External Resources and External Transactions with a CSO, its Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver net energy into New England from an external Control Area.
Area during that Capacity Scarcity Condition is due to an outage or de-rate of a Transmission Facility in the New England Control Area.
To:    Markets Committee Members and Alternates  
From:  Gary Will, Massachusetts Municipal Wholesale Electric Company on behalf of the Massachusetts entitlement holders of the NYPA Contracts  
Date:  October 18, 2013  
Subject:  Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to the Import Capacity Resources associated with the NYPA contracts.

MMWEC is concerned that the ISO New England Forward Capacity Market Performance Incentives (FCMPI) proposal will be financially damaging to the NYPA recipients and alters the long-standing treatment of the NYPA Contracts. MMWEC administers the contracts and other arrangements covering the purchase and delivery of hydroelectric power from the New York Power Authority (NYPA) to Massachusetts municipal utilities. Under an agreement with the Massachusetts Department of Telecommunications & Energy (DTE), as the official Massachusetts bargaining agent for NYPA power, MMWEC acts as the agent for DTE in overseeing the Massachusetts allocations of power and energy from the NYPA-operated hydroelectric projects in New York.

**NYPA imports are power deliveries to New England**

NYPA imports are power deliveries to New England under two contracts from NYPA’s Niagara and St. Lawrence hydroelectric projects. The two contracts entitle Public Entities to delivery of approximately 84.1 MW of firm hydropower from the NYPA projects.

The existing breakdown of the power flowing under the NYPA contracts to New England entities is as follows:

<table>
<thead>
<tr>
<th>Entity</th>
<th>MW Contract</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>13.2</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>53.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>2.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td>Vermont</td>
<td>15.3</td>
<td>8/31/2025</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>84.1</strong></td>
<td></td>
</tr>
</tbody>
</table>
NYPA capacity is Federal Preference Power
NYPA capacity is Federal Preference Power, the delivery of which is mandated by federal law and required under 50-year, FERC-approved hydroelectric licenses. The specific requirements for delivery of this preference power are found in the federal Niagara Redevelopment Act and in the FERC licenses for NYPA to operate the Niagara and St. Lawrence hydroelectric projects. These delivery requirements are supported by the results of extensive litigation before the FERC and federal courts dating back to the 1980's. These delivery requirements make the NYPA preference power allocations to New England entities unique, as there are no other external resources carrying such requirements. This is a significant distinction between NYPA power and all other New England resources, including other control area-backed transactions and demand response resources.

The NYPA contracts predate both the FCM and SMD
The NYPA contracts predate both the FCM and SMD and it is not unduly discriminatory to treat them differently. In fact, ISO-NE urged that different treatment be afforded these contracts for FCM purposes and the FERC agreed. FERC’s Jan. 8, 2008 Order Accepting Proposed Revisions to Forward Capacity Market Rules (“FERC Order”) recites (at p 19) cites ISO-NE’s contention that proposed revisions providing special treatment to the NYPA contracts "do not create undue discrimination; the proposed changes are needed to ensure that pre-existing contracts are not abrogated. It is not unduly discriminatory for the FCM rules to extend different treatment to resources that are not similarly situated."

There are several factual distinctions that make the NYPA imports unique. They are firm capacity imports that represent an almost perfectly-available resource due to the reliability of the underlying hydroelectric facilities, the firmness of power being imported, the delivery of the scheduled power at multiple interconnection points, and NYPA’s contractual replacement-energy obligations. In testimony supporting the ISO’s position in the FERC Order proceeding, Robert Ethier testified that special treatment of the NYPA contracts under the FCM rules was needed "in order to better recognize the rights of certain existing long-term import capacity contracts." He testified further that the "FCM rules should ensure that certain long-term contracts are treated in a manner consistent with their pre-existing capacity rights and obligations."

FERC supported this position, stating (FERC Order at p 26) that the "Commission’s long-standing policy, consistent with a substantial body of judicial precedent, has been to protect the stability of long-term contracts. Contracts, especially long-term contracts
like the ones at issue here, provide certainty and stability in energy markets. Hence it is not unreasonable for ISO-NE to accord different treatment to pre-existing grandfathered contracts.” Further, the FERC Order states (at p 29) that “The Commission encourages long-term contracting and is loath to undercut such contracts, which benefit the market by providing certainty and stability. Alternatively, rejecting such proposed treatment likely would chill long-term contracting.”

On March 17, 2010, ISO New England and the New England Power Pool jointly filed the FCM Competitive Import Requirements implementing changes to Market Rule 1 to require capacity importers to submit energy offers at competitive prices and to subject capacity importers to penalties for failing to comply with certain Forward Capacity Market (“FCM”) participation requirements (referred to collectively herein as the “FCM Competitive Import Requirements”) which became effective June 1, 2010 to coincide with the commencement of the first FCM Capacity Commitment Period.

That filing included an exemption for Existing Import Capacity Resources Associated with Specific Long-Term Contracts whereby… “Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) of Market Rule 1 will be exempt from the penalty provisions of the FCM Competitive Import Requirements, provided that the associated transactions are self-scheduled and perform according to their contract terms. Because these contracts were in effect before the development and implementation of New England’s Standard Market Design, specific provisions have been made when appropriate to accommodate these existing contracts.” The proposal was accepted by FERC Order issued May 20, 2010, in Docket No. ER10-902-000. In approving the revisions, the Commission stated (at page 7) that it “finds that the reformed penalty structure on the whole will provide a more meaningful incentive for capacity importers to deliver energy when they are requested to do so.”

MMWEC Proposal
Consistent with these precedents, MMWEC proposes the elimination of the provisions of FCMPI from applying to the Import Capacity Resources associated with the NYPA contracts.
To: Markets Committee Members and Alternates
From: Gary Will, Massachusetts Municipal Wholesale Electric Company
Date: October 18, 2013
Subject: Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to resources classified as Intermittent Resources.

MMWEC is concerned that the ISO New England Forward Capacity Market Performance Incentives (FCMPI) proposal will be financially damaging to Intermittent Resources. This class of resources is already discounted in the calculation of Qualified Capacity in FCM.

Intermittent Power Resources and Intermittent Settlement Only Resources Qualified Capacity is currently based on the median summer and winter reliability hours averaged over a five year period (Market Rule 1, Section 13.1.2.2.2.1 (a)-(d) and 13.1.2.2.2.2). This methodology significantly reduces these resources Qualified Capacity levels from that of its nameplate rating. Shortage Event hours are added to the total amount of reliability hours during the respective summer and winter periods (section c of each Section noted above); in effect already serving as a Performance Incentive while potentially reducing the capacity payments further.

ISO-NE’s ICR calculation and other practices and planning procedures already take into account the intermittent nature of these resources. These resources should continue to play an important role in the New England markets, yet the proposed FCMPI application to Intermittent Resources could have the unintended effect of having existing/new resources pull out from FCM and/or not get built. After all, many Intermittent Resources provide output levels in many hours well above their Capacity Supply Obligation – without getting any further incentive to do so.

**MMWEC Proposal**
MMWEC proposes the elimination of the provisions of FCMPI from applying to Intermittent Resources.
To: Markets Committee Members and Alternates  
From: Gary Will, Massachusetts Municipal Wholesale Electric Company  
Date: October 17, 2013  
Subject: Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Planned Outages

A power generating plant may not be able to deliver energy or reserves during a reserve shortage event due to being on a planned outage in accordance with ISO procedures (ISO New England Operating Procedure No. 5 - Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5)).

MMWEC proposes to eliminate the provisions for non-performance penalties from FCMPI from applying to a generator that is on an ISO sanctioned planned outage.
To: Markets Committee Members and Alternates  
From: Gary Will, Massachusetts Municipal Wholesale Electric Company  
Date: October 17, 2013  
Subject: Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Transmission Outages.

The FCMPI should examine loss of generation and/or reserves and eliminate non-performance penalties for any such loss when it is due to a loss of transmission.

Where the generation resource is ready and able to provide energy if called upon, but cannot deliver due to the loss of a transmission facility—a loss over which the generation resource has no control—there is no basis to penalize the resource. It is not as though the penalty can serve to encourage the generation resource owner to make different arrangements. Moreover, the generation resource will not receive payment for energy that is not provided. Adding an additional penalty on top of the lost opportunity is pointless and presents a risk that cannot be hedged.

MMWEC proposes to eliminate the provisions for non-performance penalties from FCMPI from applying to a generator, when such a loss is due to a loss of transmission.
NU Amendment for PI Transmission Outage Exemption
For the December 6, 2013 NPC meeting

III.13.7.2.7 Exception.

(a) For internal New England Generators and Demand Response resources with a CSO, its Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver energy or reserves during that Capacity Scarcity Condition is due to an outage or de-rate of a Transmission Facility in the New England Control Area that is beyond the control of the resource.

(b) For External Resources and External Transactions with a CSO, its Capacity Performance Score shall be set to zero if (i) that resource’s Capacity Performance Score would otherwise be negative, and (ii) the resource’s inability to deliver net energy into New England from an external Control Area during that Capacity Scarcity Condition is due to an outage or de-rate of a Transmission Facility in the New England Control Area.
Restore Prior Performance Rules for Passive Demand Resources

Markets Committee Meeting
November 14, 2013
Restore Prior Performance Rules for Passive Demand Resources

- Passive demand resources **consistently meet their resource adequacy obligations** (summer peak).
- Documenting passive demand resource performance beyond resource adequacy hours will be time-consuming and expensive.
- Passive demand resources by their very nature do not respond to price signals.
- As such it does not make sense to subject them to the Pay for Performance proposal which implicitly assumes resources can respond to energy and operating reserve market price signals.
The following Market Rule 1 sections are restored and modified to restore prior performance rules for passive demand resources. To the extent the old sections were reused, renumbering will be necessary.

III.13.7.1.5. Demand Resources.
III.13.7.1.5.1. Capacity Values of Demand Resources.
III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.
III.13.7.1.5.3. Demand Reduction Values.
III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.
III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.
III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.
III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.
III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.
III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
Restore Prior Performance Rules for Passive Demand Resources

The following Market Rule 1 sections are restored & / or modified to restore prior performance rules for passive demand resources. To the extent the old sections were reused, renumbering will be necessary. Continued.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.
III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.
III.13.7.2 Capacity Performance Payments.
III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition. (b) and (c)
III.13.7.2.7.5. Demand Resources.
III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.
III.13.7.2.7.5.2. Negative Monthly Capacity Variances.
III.13.7.2.7.5.3. Positive Monthly Capacity Variances.
III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.
SECTION III
MARKET RULE 1
STANDARD MARKET DESIGN

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.
The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.3. Demand Reduction Values.
A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, and III.13.7.1.5.6, III.13.7.1.5.7, and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.
Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.
Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.
III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.
The summer seasonal Demand Reduction Value for the months of September, October, November, April, and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.2.7.5. Demand Resources.

Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1. On-Peak and Seasonal Peak Demand Resource payments shall be modified solely by the provisions of this section, section III.13.7.2.7.5.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of an Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of an Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to
apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource’s Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource’s Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the
Case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or to the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particular Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.
The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2 Capacity Performance Payments.

On Peak and Seasonal Peak Demand Response Resources will not be subject to this section but rather to section III.13.7.2.7.5.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

(a) An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource On-Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. An On-Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource On-Peak Hours and shall be zero.

(b) A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition occurring during Demand Resource Seasonal Peak Hours shall be the resource’s Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. A Seasonal Peak Demand Resource’s Actual Capacity Provided during a Capacity Shortage Condition not occurring during Demand Resource Seasonal Peak Hours and shall be zero.
Reinstate FCM Provisions for Existing Generation

Markets Committee Meeting
October 29, 2013
Reinstate FCM Provisions for Existing Generation

- While it may be appropriate to change capacity market performance expectations for resources yet to clear it is **not** appropriate for the existing fleet built under a different paradigm.
- The current availability provisions for existing generation properly reflect what should be expected of them and should remain.
- Restore existing generation provisions in section III.13.7.1.3 so as to use the resulting hourly MW values in the Capacity Performance Payment calculation.
- Any underfunding of incentive payments would use the proposed method in section III.13.7.4; alternatively incentive payments could be reduced by underfunded amount.
SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN
III.13.7.1.1.3. Hourly Available MW Value for Use in Capacity Performance Payments as Described in Section III.13.7.2.

The following MW values shall be used in the Capacity Performance Payment calculations for any scarcity event occurring during the hour. A resource’s available MW in each hour that contains any portion of a scarcity shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource’s available MW in an hour exceed that resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource). The provisions of Section III.13.7.1.1.3 shall apply to each non-intermittent generation resource qualified as existing in forward capacity auction 9 until such time as it ceases to qualify as a capacity resource.

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.
(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.3(b) or Section III.13.7.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource’s metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or derate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource’s available MW in an hour shall not be reduced as a result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource’s available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.
FCM PI
EquiPower Proposal for Administrative Delist

November 13-14, 2013 Markets Committee
Issue

- Resources, on average, will miss a certain fraction of Reserve Shortages based on their average unit unavailability.
  - Ignoring transmission outages, maintenance, start time and other limitations, this can be represented by EFORd x Qualified Capacity
    - It is the minimum amount that we would typically believe is unavailable.
  - Because we know the associated MWs will likely miss these Events, the expected value of PI payments for these MWs can be negative – and much different from expectation for other MWs.
  - Gens should have the ability to avoid a CSO for these MWs that, on average, will not be there.
    - Ability to price these MWs using proposed Tariff formulae may not mesh with risk managers’ perspectives.
Solution

- Allow an “Administrative Delist” for EFORd x Qualified Capacity.
  - MWs can be removed from the auction at the starting price; if entered at that level, they cannot receive a CSO, and cannot set price.
  - Mechanism is identical to “Ambient Air Delist.”
Add the following new section below the existing Ambient Air Rule:

III.13.1.2.3.2.4.1 Static De-List Bids for Reductions in Ratings Due to EFORd

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects may not be physically available due expected unavailability represented by EFORd times summer Qualified Capacity at 90 degrees. EFORd shall be the value, as reported through GADS, for the most recent Capacity Commitment Period prior to time at which the FCM qualification process takes place. The ISO shall verify during the qualification process that the value is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

Note: Language is modeled on existing Ambient Air process. Red wording shows difference from Ambient Air language.
PER Provisions

(as marked by ISO for FCM PI Proposal)
III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3. During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.


Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.


Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

[Text below moved from old Section III.13.7.2.1.1, then redlined.]
(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

[This is old Section III.13.7.1.1 being deleted] During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any Shortage Events during the month.
III.13.7.1.22.7.1.1. Peak Energy Rents. [Text below moved from old Section III.13.7.2.7.1.1, then redlined.]

Capacity Base Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.12.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER}($/kW) = \left[(\text{LMP} - \text{Strike Price})\right] \times \text{Scaling Factor} \times \text{Availability Factor}
\]

Where:

Strike Price — the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor — the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor — 0.95.
(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run-time constraints.

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.22.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource), provided, however, that in no case shall a resource’s PER deduction for an Obligation Month be less than zero or greater than the resource’s Capacity Base Payment for the Obligation Month.

\[
\text{PER Adjustment} = \min((i) \text{ the PER cap or (ii) the Average Monthly PER } \times \text{ PER-Capacity Supply Obligation})
\]

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction...
for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments. [Moved to new Section III.13.7.1.1, then redlined.]

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) Forward Capacity Auction. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England
Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

### III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

### III.13.7.1.32.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).
Charge Amount to Resource Exporting = \( [\text{Capacity Clearing Price}_\text{location of the interface} - \text{Capacity Clearing Price}_\text{location of the resource}] \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid} \)

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = \( [\text{Capacity Clearing Price}_\text{location of the interface} - \text{Capacity Clearing Price}_\text{location of the resource}] \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid} \)

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.
An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.
III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.
Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.
Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.
III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources.

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources.

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.1.5.2.5.4 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during
Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.15.12.5.4.1 Adjustment for Net Supply Generator Assets.

For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource-designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents. [Moved to new Section III.13.7.1.2, then redlined.]

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.
(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER} (\$/kW) = [(LMP - Strike Price) \times \text{Scaling Factor} \times \text{Availability Factor}]
\]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run-time constraints.

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the
III.13.7.2.7.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

$$\text{PER Adjustment} = \min \left( (i) \text{ the PER cap or (ii) the Average Monthly PER} \times \text{PER Capacity Supply Obligation} \right)$$

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the
resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

\[
\text{Penalty} = \text{[Resource’s Annualized FCA Payment]} \times PF \times [1 - \text{Shortage Event Availability Score}]
\]

Where:

- Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource’s Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

- PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) Per Day. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource’s Annualized FCA Payment for that Capacity Commitment Period.
(b) **Per Month.** The sum of a resource’s penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

**III.13.7.2.7.1.4. Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.**

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro-rata share of availability penalties paid by other capacity resources.
To: Markets Committee Members and Alternates

From: Tom Kaslow

Date: Tuesday, October 29, 2013

Subject: Correction - Alternative Changes to Modify the Peak Energy Rent Mechanism

Prior to the October 8th NEPOOL Markets Committee (MC) meeting, GDF SUEZ Energy Marketing North America (GSEMNA) provided a memo explaining its alternative proposal to modify the Peak Energy Rent (PER) deduction in the event that its preferred solution, an amendment to eliminate the PER deduction was not accepted. While the specific tariff changes for this alternative amendment were accurately drafted for the early October MC meeting, the explanatory memo for that meeting failed to accurately describe the changes. GSEMNA offers the following explanation that accurately describes its proposed changes for this meeting:

(1) Calculate the hourly PER based on Day Ahead Energy Market (DAEM) prices where energy from Capacity Supply Obligation (CSO) megawatts are sold at the DAEM price and deliver energy, operating reserves or Regulation in real time.

(2) Calculate the hourly PER based on the lower of the real time operating reserve price for thirty minute operating reserves or the real-time Locational Marginal Price (LMP) for CSO megawatts which do not have a DAEM sale and provide operating reserves, not energy, in real time. These CSO megawatts receive the Real Time Operating Reserve price and not the Real Time Energy Market price. As a consequence, the PER deduction should not exceed the real time price for thirty minute operating reserves.

(3) Set the hourly PER to zero for CSO megawatts which do not have a DAEM sale and supply Regulation service in real time. Despite supplying operating reserves, unloaded Regulation megawatts are not designated as operating reserves in the ISO-NE market settlements and do not receive a payment for real time operating reserve. While the opportunity cost element of the Regulation clearing price is intended to be at least equal to their lost operating reserve opportunity, that is not always achieved. Given the very small size of the Regulation market and the inefficiency of requiring Regulation providers to guess whether a PER hour could arise and the extent to which such risk would not be covered by the lost opportunity component of the Regulation clearing price, GSEMNA proposes to simply set the hourly PER to zero for these resources and not require Regulation suppliers to bid in potential PER risks into their Regulation offers.
PER Provisions

(as marked by ISO for FCM PI Proposal)
III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.


Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.


Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in
the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

[This is old Section III.13.7.1.1 being deleted.]

III.13.7.1.2 **Peak Energy Rents.** [Text below moved from old Section III.13.7.2.7.1.1, then redlined.]

Capacity Base Payments to resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs, Day-Ahead LMPs, and Real Time Operating Reserve prices. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs, Day-Ahead LMPs and Real Time Operating Reserve prices for each Capacity Zone, using the Real-Time Hub Price, Day-Ahead Hub Price, and Rest-of-Pool Real Time Operating Reserve prices.
for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

### III.13.7.1.2.1 Hourly PER Calculations.

(a) Where the respective portion of resources with Capacity Supply Obligations are not: (i) scheduled as energy in the Day-Ahead Energy Market, (i) designated as real time operating reserves from megawatts denied a real time self-scheduling request, or (iii) providing Regulation in real time, for hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER}($/kW) = (\text{RTLMP} - \text{Strike Price}) \times \text{Scaling Factor} \times \text{Availability Factor}
\]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) Where the respective portion of resources with Capacity Supply Obligations are scheduled as energy in the Day-Ahead Energy Market and delivered in real time as energy, operating reserves or Regulation, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER}($/kW) = (\text{DALMP} - \text{Strike Price}) \times \text{Scaling Factor} \times \text{Availability Factor}
\]
Where the respective portion of resources with Capacity Supply Obligations are not scheduled as energy in the Day-Ahead Energy Market and are designated as real time operating reserves from megawatts denied a real time self-scheduling request, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

\[
\text{Hourly PER} \ (\$/\text{kW}) = \min[\text{RTOR Price}, \text{RTLMP} - \text{Strike Price}] \times [\text{Scaling Factor}] \times [\text{Availability Factor}]
\]

Where,
\[
\text{RTOR Price} = \text{the Real Time Operating Reserve price for Thirty Minute Operating Reserves.}
\]

Where the respective portion of resources with Capacity Supply Obligations are not scheduled as energy in the Day-Ahead Energy Market and provided Regulation in the hour, the ISO shall set PER for each such hour ("Hourly PER") equal to zero:

\[
\text{Hourly PER} \ (\$/\text{kW}) = 0
\]

PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.
III.13.7.1.2.2 Monthly PER Application.

The Hourly PER shall be summed for each resource with a Capacity Supply Obligation for that calendar month to determine the total PER for that resource in that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER for each resource shall be equal to the average of the Monthly PER values for that resource for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER for that resource multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource’s PER deduction for an Obligation Month be less than zero or greater than the resource’s Capacity Base Payment for the Obligation Month. [Moved to new Section III.13.7.1.1, then redlined.]

III.13.7.1.3 Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

\[
\text{Charge Amount to Resource Exporting} = \left( \text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}} \right) \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid}
\]

\[
\text{Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located} = \left( \text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}} \right) \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid}
\]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.3.1.
III.13.7.1.4 Monthly Capacity Payments for Real-Time Emergency Generation Resources.
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.1.5 Energy Settlement for Real-Time Emergency Generation Resources
A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.1.5.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.1.5.1 Adjustment for Net Supply Generator Assets.
For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

[Moved to new Section III.13.7.1.2, then redlined.]
Alternative to ISO-NE’s Performance Incentives

Markets Committee Meeting
November, 2013
6 Capacity Market Changes To Increase Resource Performance

1. Convert FCA format from ICAP to UCAP using GAD’s EFORd data.
   - Stop grossing up the NICR calculation to compensate for resource underperformance & compensate resources based on what they have demonstrated, over the previous 12 months, they can deliver via EFORd.

2. Require resources to true-up capacity obligations 1-year prior to the commitment period based on recent annual EFORd performance.

3. Expand treatment for ‘New’ Capacity Resources.
   - Increase the ‘New’ resource lock-in period from 4 to 6 years and incent investment by including criteria for flexible fueling arrangements (investment in dual fuel, etc.)

4. Increase the Dynamic Delist Threshold Price to $4.65/kW-month.

5. Establish a Pivotal Supplier review of delist bids from existing resources.
   - The existing IMM criteria to review a Market Participant’s NRAGFC is vague.

6. Allow the FERC approved, modified Shortage Event trigger time to work.
QUESTIONS
DOMINION PROPOSAL

(Dominion’s Alternative to the ISO’s FCM PI Proposal)

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a Qualified Unforced Capacity (UCAP) value for each resource, a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.


To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.2.2.4.


A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.
III.13.1.1.1. **Resources Never Previously Counted as Capacity.**

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.2. **Resources Previously Counted as Capacity.**

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.2. The incremental expenditure required to reactivate 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) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following **three-four** subsections:
(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource’s summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource’s summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

(d) Where investment in the resource subsequent to January 1, 2014 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of making fuel security improvements through capital investment or fuel contract agreements for a minimum of 10 years which meet criteria established for this section by the Internal Market Monitor, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource.
III.13.1.1.2.2.4. **Capacity Commitment Period Election.**

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four-six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. **Additional Requirements for Resources Previously Counted As Capacity.**

In addition to the information described elsewhere in this Section III.13.1.1.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.2(b), III.13.1.1.3(b), and III.13.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, or III.13.1.1.1.4, the Project Sponsor
must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.2.2.2.

(d) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.2.1(c)(fuel security), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the capital project proposed to improve fuel security or a detailed description of the proposed long-term fuel contract; and (ii) documentation of the costs associated with the project or contract.

III.13.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and converted to a UCAP value using the class average EFORd for the 12 months prior to the New Capacity Qualification Deadline for the type of resource, and possibly as modified pursuant to Section III.13.1.2.3(b).

III.13.1.2.5.2. [Reserved]

III.13.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.2.4(e) and converted to a UCAP value using the class average EFORd for the 12 months prior to the New Capacity Qualification Deadline for the type of intermittent resource. The FCA Qualified Capacity for such a resource shall be equal to the resource’s summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.
III.13.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a 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 amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation, and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings,
or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation, and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation, and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource’s winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource’s previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation, and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of
capacity clearing from the resource as a New Generating Capacity Resource in previous Forward
Capacity Auctions.

**III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power
Resources and Intermittent Settlement Only Resources.**

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run
of river hydro and other renewable resources that do not have control over their net power output. Wind
and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only
Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that
is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as
follows:

**III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and
Intermittent Settlement Only Resource.**

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the
ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only
Resource’s net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or
Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full
summer periods, the ISO shall determine the median of the Intermittent Power Resource’s net output in
each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent
Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent
Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006
summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be
established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section
III.13.1.1.2.4(e).

(b) The Intermittent Power Resource’s or Intermittent Settlement Only Resource’s summer Qualified
Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) 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 the ISO has declared
a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only
Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.
(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource’s and Intermittent Settlement Only Resource’s net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource’s and Intermittent Settlement Only Resource’s winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) 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 the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource’s winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.
III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource’s winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource’s Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.
Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1 before the UCAP adjustment, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource’s summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORD rating for the 12 months prior to the Existing Capacity Qualification 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 Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 before the UCAP adjustment and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource’s summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.
Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.3(a) but not the requirements of Section III.13.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource’s summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource’s positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.3(a)], and converted to a UCAP value using the Existing Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource’s summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made
pursuant to this Section III.13.1.2.5.2 shall be subject to a reliability review as described in Section III.13.2.5.2.5, as required. This Section III.13.1.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.
For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource’s Lead Market Participant of the resource’s summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.
A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity
Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

### III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $4.65/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

### III.13.1.2.3.1.1 Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to opt out of the capacity market at prices at or above the Dynamic De-List Bid Threshold $1.00/kW-month during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic
Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to opt out of the capacity market permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource’s full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.
III.13.1.2.3.1.3. Export Bids.
An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.
For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if: (1) at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) from the previous Forward Capacity Auction is less than or equal to the greater of:
   (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and
   (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;
or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for
the import-constrained Capacity Zone from the previous Forward Capacity Auction is less than or equal to the greater of:

(a) the amount of capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold $1.00/kW-month, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold $1.00/kW-month.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold $1.00/kW-month, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month to determine whether the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.1) and opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.2). Sufficient documentation and information must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs and 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 resource, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.
The Internal Market Monitor may seek additional information from the Lead Market Participant after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered
into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW–month.

III.13.1.2.3.2.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold $1.00/kW–month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with
the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW-month.

(b)(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold $1.00/kW-month.

III.13.1.2.3.2.2.2. Net Risk-Adjusted Going Forward Costs.

A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold $1.00/kW-month, or Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month shall be considered consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward costs based
on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

\[
\left( \frac{GFC - (IMR - PER)}{CQ_{Summer} \times kW \times 12, \text{months}} \right) \times \text{Inflation Index}
\]

Where:

GFC = annual going forward costs, in dollars. These are costs 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 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 Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

\[CQ_{Summer} \times kW = \text{capacity seeking to de-list in kW. In no case shall this value exceed the resource’s summer Qualified Capacity.}\]

RF = risk factor, in dollars. This value shall be calculated using the following formula:
RF = [(RPC x EFORd) + (P x (Forward Capacity Auction Starting Price – AFCAP) x 12,months)] x CQ_{Summer kW}

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit’s daily price to the resource’s Real-Time nodal price. For each hour that the resource’s nodal price exceeds the PER Proxy Unit’s daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit’s daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.

P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource’s Capacity Zone.

AA = availability adjustment. AA = (1 – EFORd)

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.
EFOR\textsubscript{d} shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual 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 Existing Generating Capacity Resource’s total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource’s total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.

\[ \text{InfIndex} = \text{inflation index.} \text{ infIndex} = (1 + i)^4 \]

Where: “\(i\)” is the most recent reported 4 Year expected inflation number published by the Federal Reserve Bank of Cleveland 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Opportunity Costs.
To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold\$1.00/kW-month, or Permanent De-List Bid above...
Dynamic De-List Bid Threshold\$1.00/kW-month has **additional** opportunity costs that support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, 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. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

III.13.1.2.3.2.2.  [Reserved.]

III.13.1.2.3.2.3.  **Administrative Export De-List Bids.**

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4.  **Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.**

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to
ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

<table>
<thead>
<tr>
<th>Age of Existing Resource (years)</th>
<th>Remaining Life (years)</th>
<th>Annual Rate of Capital Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 to 5</td>
<td>30</td>
<td>0.106</td>
</tr>
<tr>
<td>6 to 10</td>
<td>25</td>
<td>0.110</td>
</tr>
<tr>
<td>11 to 15</td>
<td>20</td>
<td>0.117</td>
</tr>
<tr>
<td>16 to 20</td>
<td>15</td>
<td>0.131</td>
</tr>
<tr>
<td>21 to 25</td>
<td>10</td>
<td>0.163</td>
</tr>
<tr>
<td>25 plus</td>
<td>5</td>
<td>0.264</td>
</tr>
</tbody>
</table>

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

\[
\frac{\text{Cost Of Capital}}{(1-(1+\text{Cost Of Capital})^{-\text{Remaining Life}})}
\]

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.
Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

### III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3. and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

### III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.
III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource’s Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.
(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold $1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The amount of capacity procured will be based on UCAP values offered into the Forward Capacity Auction by qualified resources. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). If a Capacity Zone has a Forward Capacity Auction Starting Price (determined in accordance with Section III.13.2.4) below the End-of-Round Price, then that Capacity Zone shall not be included in the round. In the first round, the Start-of-Round Price shall equal the highest Forward Capacity Auction Starting Price of all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A
New Capacity Offer for a resource may not be for less capacity than the resource’s Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be $P_S$ and $P_E$, respectively. Let the $m$ prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor’s supply curve, for all prices strictly less than $P_S$ but greater than or equal to $P_E$, shall be taken to be:

$$S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\vdots & \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}$$

where, in the first round, $q_0$ is the resource’s full FCA Qualified Capacity and, in subsequent rounds, $q_0$ is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-
List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold $1.00/kW-month (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round’s relevant prices,
pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction
reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.
III.13.2.7.9  Capacity Carry Forward Rule.

III.13.2.7.9.1.  Trigger.
The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2.  Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8.  Inadequate Supply and Insufficient Competition.
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate
Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.
An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone’s Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity...
Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.
The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.
(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);
(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section III.13.2.8.2, a Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.3.4. Covering Capacity Supply Obligation where Resource will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period.

If as a result of milestone date revisions made pursuant to Section III.13.3.3, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except for a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation in the circumstances described in Section III.13.7.1.1.3(h) and Section III.13.7.1.1.3(i)), then the Project Sponsor must take
actions to cover the entire Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, as follows:

(a) The Project Sponsor may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4 or one or more Capacity Supply Obligation Bilaterals, which must be submitted to the ISO as described in Section III.13.5.

(b) If, by the time demand bids are due for the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, the Project Sponsor has not covered its full Capacity Supply Obligation for the portion of the Capacity Commitment Period for which the project will not have achieved Commercial Operation, then the ISO shall submit a demand bid in that annual reconfiguration auction on the Project Sponsor’s behalf for a quantity equal to the largest monthly Capacity Supply Obligation for the Capacity Commitment Period that has not been covered, at the Forward Capacity Auction Starting Price (with all payments, charges, rights, obligations, and other results associated with such demand bid applying to the Project Sponsor as if the Project Sponsor itself had submitted the demand bid).

(c) If the Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if the Capacity Supply Obligation is not covered as described in Sections III.13.3.4(a) and III.13.3.4(b), or if the Project Sponsor covers the Capacity Supply Obligation for two Capacity Commitment Periods, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource’s Capacity Supply Obligation for any future Capacity Commitment Periods and the resource’s right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource’s qualified capacity for participation in the Forward Capacity Market. Upon Commission ruling, the Project Sponsor 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’s Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO’s right to revoke that permission and to file with the Commission to terminate the resource’s Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

III.13.3.5. Termination of Interconnection Agreement.
If the ISO files with the Commission to terminate a resource’s Capacity Supply Obligation as described in Section III.13.3.4(c), the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4.
III.13.4. **Reconfiguration Auctions.**

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting internal and external transmission limits and regional and local sourcing requirements updated using a methodology that is consistent with the Forward Capacity Auction) 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.13.4.1. **Capacity Zones Included in Reconfiguration Auctions.**

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. **Participation in Reconfiguration Auctions.**

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions, except Real-Time Emergency Generation Resources which may only submit demand bids. In accordance with Section III.A.9.2 of Appendix A of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource’s Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. 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. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will 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.13.4.2.

III.13.4.2.1. Supply Offers.
Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Non-Price Retirement Request or a Permanent De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.
For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power
Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource’s summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Qualification Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period, and converted to a UCAP value using the Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

### III.13.4.2.1.2.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the higher of the resource’s winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Qualification Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period, and converted to a UCAP value using the Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity...
Qualification Deadline. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values
determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.4. Demand Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which
the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved Commercial Operation, the resource’s most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s summer Seasonal Claimed Capability value in effect after the most recently completed summer period, and converted to a UCAP value using the Generating Capacity Resource’s annual EFORD rating for for the 12 months prior to the Existing Capacity Qualification Deadline. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction
for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource’s CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.2.3(f):

(a) For capacity that has achieved Commercial Operation, the resource’s winter Seasonal Claimed Capability value in effect after the most recently completed winter period, and converted to a UCAP value using the Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline. The amount of capacity described in this Section III.13.4.2.1.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not become commercial.

(b) Any amount of capacity that has not yet achieved Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) has a Commercial Operation milestone date that is prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved Commercial Operation, the ISO shall subtract the resource’s Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of...
capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values, if the resource’s Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by more than the lesser of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or 40 MW, then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3. A resource may submit Capacity Supply Obligation Bilaterals to cover the deficiency, in whole or in part, prior to the third annual reconfiguration auction.

(c) If the ISO determines that the resource is not able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, and if the resource was part of an offer composed of separate resources when it qualified to participate in the relevant Forward Capacity Auction, then before a demand bid is entered for the resource pursuant to subsection (b) above, the resource may submit monthly Capacity Supply Obligation Bilaterals to cover the deficiency for the months of the Capacity Commitment Period in which the Capacity Supply Obligation is associated with participation in an offer composed of separate resource prior to the third annual reconfiguration auction, but in no case may such a Capacity Supply Obligation Bilateral for a
month be for an amount of capacity greater than the difference between the resource’s Capacity Supply Obligation for the month and the resource’s lowest monthly Capacity Supply Obligation during the Capacity Commitment Period.

III.13.4.2.1.4. **Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.**

A resource that has not achieved Commercial Operation by the offer and bid deadline for a monthly reconfiguration auction may not submit a supply offer for that reconfiguration auction, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. 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 Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period; and (ii) the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month. However, a resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month.

III.13.5.3. **Supplemental Availability Bilaterals.**

A resource’s availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. **Designation of Supplemental Capacity Resources.**

III.13.5.3.1.1. **Eligibility.**

Demand Response Capacity Resources and Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource and converted to a UCAP value using the Generating Capacity Resource’s annual EFORd rating for the 12 months prior to the Existing Capacity Qualification Deadline, and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource. A Demand Response Capacity Resource may be designated as a Supplemental...
Capacity Resource in a MW amount up to the difference between the resource’s Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period pursuant to Section III.13.1.4.1 and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.
III.13.7.3.1 Opt-Out for Resources Electing Multiple-Year Treatment

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in Forward Capacity Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline, opt out of the remaining years of the resource’s multiple-year election. A decision to so opt out shall be irrevocable. A resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.
III.13.8.  Reporting and Price Finality

III.13.8.1.  Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward 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;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor’s determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor’s
determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource’s long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor’s determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids from resources associated with pivotal Lead Market Participants as described in Section III.13.1.2.3.2 based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO’s submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO’s submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO’s submission of the informational filing, the Commission does issue an order modifying one or more of the ISO’s determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices
resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO’s filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.
November 27, 2013

Memorandum

To: NEPOOL Participants Committee
From: Pete Fuller, NRG

RE: NRG Proposal Regarding Market Reforms

This memo describes several changes in the Market Reform proposals being presented by NRG for consideration by the Participants Committee at its December 6, 2013 meeting, as compared to the proposal considered by the Markets Committee (MC) at its November 13, 2013 meeting. At that meeting, the MC voted 31.65% to support the NRG Alternative to ISO-NE’s FCM Performance Incentives proposal, which received substantially less support than the NRG Alternative.

Based on feedback from stakeholders, NRG will be asking the Participants Committee to vote on the same substance considered by the MC, but in three separate votes, as described below.

NRG Amendment #1
NRG’s first amendment represents the first two elements of NRG’s Markets Committee proposal, that is, changes to the energy and ancillary service markets to improve price formation in those markets both during normal operations as well as during periods of reserve scarcity, and a proposal for a capacity availability metric based on EFORp.

As described in materials presented over the past several months to the MC, NRG supports addressing the real-time price formation and operational incentives identified by ISO-NE\(^1\) in the real-time markets for energy and ancillary services, rather than through a fundamental re-definition of the capacity product procured in FCM. Areas that warrant potential market rule changes in this regard include, but are not necessarily limited to, i) consider establishing real-time energy prices based on the full cost of meeting all of the energy and reserve needs in light of transmission constraints, rather than on the basis of the next dispatchable MWh; ii) correcting price suppression caused by out-of-merit dispatch and other un-priced operator actions; iii) eliminating any inappropriate hedging between DA and RT provided by ISO reliability actions; and iv) consider allowing resources to include start-up and no-load costs in their energy offers.

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In addition, NRG supports as part of this proposal exploration of one or more additional ancillary service products, to better support real-time load-following and other operational requirements to supplement the contingency response needs represented in the current real-time and forward reserve markets, although NRG has no specific proposal at this time.

As reflected in tariff language to be voted on by the PC, NRG proposes to increase the Reserve Constraint Penalty Factors (RCPF) for System TMOR from $500 to $1,000, and for System TMNSR from $850 to $1,500. These increases, in Section III.2.7A of the tariff, would ensure that all resources offered in the energy market are available to the dispatch software to maintain adequate reserves on the system and provide a better indication of scarcity conditions, as well as providing increased real-time incentives for availability and production in response to ISO-NE energy and reserve needs, which addresses an important element that ISO-NE identified in its October 2012 whitepaper and subsequent materials.

The EFORp mechanism would replace the FCM’s ‘Shortage Event’ mechanism for measuring the ‘performance’ of resources with Capacity Supply Obligations. Instead of measuring availability only during Shortage Events, the proposed mechanism would measure availability, using the existing standards in the tariff, during all ‘EFORp Hours’, which would be four afternoon hours on summer weekdays and two evening hours on winter weekdays, corresponding to hours when system load is expected to be highest, and thus the adequacy of overall supply would be most at risk. The proposal would create an additional incentive for high availability during those hours through an incremental charge or payment, based on 150% of the FCM Clearing Price, for deviations from a Resource’s EFORp availability over the prior five years. The mechanism is more fully described in NRG’s MC materials\(^2\) and in the proposed tariff language.

The tariff changes to implement this proposal are contained in Sections III.2.7A and III.13.7 of Market Rule 1.

**NRG Amendment #2**

NRG’s second proposed amendment is to eliminate the PER mechanism. Consistent with the intent of NRG’s first amendment, which is to maintain distinct energy, ancillary service and capacity products and markets, NRG proposes to eliminate this mechanism which inappropriately links the capacity and energy markets. The PER mechanism is an inefficient hedge for buyers, requiring consumers to buy a real time energy price hedge which far exceeds the quantity of energy they actually purchase in the real-time market. The PER mechanism has always been an inefficient and superfluous tool to address either of its stated objectives – real-time price mitigation and hedging load against high real-time prices – and should be eliminated.

The tariff changes to implement this proposal are contained in Section III.13.7 of Market Rule 1, and are presented for PC consideration as incremental to the changes proposed in NRG Amendment #1.

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\(^2\) [http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_presentation_10_08_13.ppt](http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_presentation_10_08_13.ppt)
NRG Amendment #3
NRG’s third proposed amendment is to revise the interaction of Existing Resources with the Forward Capacity Auction, with a goal of supporting more stable FCM pricing over time that will better support investment and reliability. The proposed changes would i) establish the dynamic delist bid threshold at 80% of the Offer Review Trigger Price of a Combustion Turbine, consistent with the original FCM design; ii) revise the IMM’s standard for evaluating price offers from Existing Resources to be the resource’s ‘long-run average costs’, rather than the ‘net risk-adjusted going-forward costs’ currently in the tariff; and iii) enable Existing Resources with IMM-approved offers above the dynamic delist bid threshold to participate fully in the descending clock auction at prices below the IMM-approved price.

By enabling all resources, both Existing and New, to compete on the basis of long-run costs, the long-run equilibrium price of capacity would be far more stable, and should more closely approximate the long-run cost of new entry. That stability around the long-run revenue needs of investors would substantially improve prospects for private investment and innovation, leading to lower costs and greater efficiencies for the region and lower risk for consumers.

The tariff changes to implement this proposal are contained in Sections III.13.1.2.3, III.13.1.2.4, III.13.1.8, III.13.2.5.2.1 and III.13.8 of Market Rule 1.

Thank you for your consideration of these proposals.
SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN
‘NRG Alternative’ Market Reform Proposals – Amendment #1 - December 6, 2013 Participants Committee Meeting

NRG Amendment #1 – Part 1 of 2, Section III.2.7A

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to create additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation Node for the generating Resource and (ii) the offer price associated with the reduction of the generating...
Resource’s output necessary to create the additional Operating Reserve or local TMOR from the generating Resource’s expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Requirement Sub-Category</th>
<th>RCPF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local TMOR</td>
<td></td>
<td>$250/MWh</td>
</tr>
<tr>
<td>System TMOR</td>
<td>minimum TMOR</td>
<td>$500-1,000/MWh</td>
</tr>
<tr>
<td></td>
<td>Replacement Reserve</td>
<td>$250/MWh</td>
</tr>
<tr>
<td>System TMNSR</td>
<td></td>
<td>$850-1,500/MWh</td>
</tr>
<tr>
<td>System TMSR</td>
<td></td>
<td>$50/MWh</td>
</tr>
</tbody>
</table>

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO’s Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the
preceding interval. The prices produced at five-minute intervals during an hour will be integrated to
determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour
to be used in settlements.
III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period (“Obligation Month”), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.


III.13.7.1.1. Generating Capacity Resources.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) Forward Capacity Auction. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in...
the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any **Shortage Events** during the month.

**III.13.7.1.1.1. Definition of Shortage Events.**

**EFORp Hours shall be the hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January.**

(a) A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.
In an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone.

An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest of Pool Capacity Zone but not for that export-constrained Capacity Zone.

In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A  **Shortage Event EFORp Hours Availability Score.**

For each **Shortage Event EFORp Hour**, the ISO shall calculate an **Shortage Event EFORp Hour Availability Score** for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource’s hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource’s **Shortage Event Availability Score** and shall accumulate and average the hourly scores to calculate an **annual EFORp Hour Availability Score** for each resource.
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III.13.7.1.1.2. Hourly Availability Scores.
The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource’s availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource’s available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource’s Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.
A resource’s available MW in each hour that contains any portion of a Shortage Event is an EFORp Hour shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource’s available MW in an hour exceed that resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.
(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource’s metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource’s available MW in an hour shall not be reduced as a result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource’s available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.
III.13.7.1.1.4. Availability Adjustments.

(a) A resource’s hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource’s Capacity Supply Obligation, if any, during each hour of the Shortage Event EFORp Hour may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for each EFORp Hour.

(b) A resource’s hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO’s annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource’s hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event EFORp Hour as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criterion: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation – (a) the resource received 3 annual availability scores of less than or equal to 40 percent, and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event that is an EFORp Hour. If both of these...
criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource’s performance.

III.13.7.1.2. Import Capacity.
The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Event EFORp Hours as defined in Section III.13.7.1.1.1. An Import Capacity Resource’s Shortage Event EFORp Hour Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event is an EFORp Hour shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource’s available MW in the hour shall be zero.
Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.
The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.
The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.
A Non-Intermittent Settlement Only Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in any Shortage Event Hour of a Shortage Event shall be the resource’s metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.
The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.
III.13.7.1.5.1. **Capacity Values of Demand Resources.**

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. **Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.**

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the
Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.
For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset’s monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer’s load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.
A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.
Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.
III.13.7.1.5.4.1. **Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. **Winter Seasonal Demand Reduction Value.**

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. **Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.**

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. **Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.
III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

(a)

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand
Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.
An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

**III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources.**

Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.
If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month's Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.7.1.5.8.1. **Summer Seasonal Demand Reduction Value.**

The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. **Winter Seasonal Demand Reduction Value.**

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. **Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.**
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.


An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources.
Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.


Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Event EFORp Hours as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource’s Shortage Event EFORp Hour Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the
ability to reduce demand, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event is an EFORp Hour shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource’s available MW in an hour exceed that resource’s Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply Generator Asset, shall be reducted by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(a) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instructions where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than (the Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (the resource’s Real-Time Demand Reduction Obligation plus the Net Supply for any associated available Net Supply Generator Assets) and the lesser of (the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Economic Maximum Limit for any associated available Net Supply Generator Assets), the resource’s Hourly Adjusted Audited Demand Reduction, or (the resource’s Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant).
(b) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instruction where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is equal to Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets or (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets) or total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than the Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation plus any associated Net Supply is less than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply for the hour.

(d) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets that have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the lesser of the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) of thirty minutes or less, the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, and Actual Load) plus the sum of
the Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or
redeclared by the Lead market Participant) or Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not reducing demand, is available for dispatch and is
able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the
Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator
Assets as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time
(adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12
hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full-
Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated
available Net Supply Generator Assets) and Offered Full Reduction Time (adjusted for the Audited
Demand Reduction), in which case the available MW in an hour shall be the lesser of (the lesser of (the
resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, the
resource’s Actual Load plus Economic Maximum Limits for any associated available Net Supply
Generator Assets as submitted or redeclared by the Lead Market Participant) or the resource’s Hourly
Adjusted Audited Demand Reduction) time weighted to reflect the portion of the hour in which the
Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceed
the Shortage Event duration.

(g) For a Demand Response Resource that (i) is not reducing demand, is available for dispatch and is
able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the
Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator
Assets) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12
hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction.
A Demand Response Resource’s Adjusted Audited Demand Reduction shall be determined as follows.
For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds
the Demand Response Baseline, adjusted pursuant to Section III.8B.5 of a Demand Response Asset
located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of
the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-
Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction set equal to the resource’s Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{\text{(the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}}{\text{(the Offered Full Reduction Time adjusted for the Audited Demand Reduction))}} \times \min(\text{Audited Demand Reduction}, \text{Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets})
\]

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{\text{(the Offered Full Reduction Time adjusted for the Audited Demand Reduction) \times \min(\text{Audited Demand Reduction}, \text{Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets})}}{\text{(the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}}
\]
The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

### III.13.7.1.5.10.2 Availability Adjustments

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Capacity Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource’s hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced reduction or scheduled reduction.

   (i) A forced reduction can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced reduction. The forced reduction can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource.

   (ii) A scheduled reduction must be submitted to the ISO at least 15 days ahead of the start of the reduction to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment. The scheduled
reduction cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource. Scheduled reductions must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus Economic Maximum Limit for any associated available Net Supply Generator Assets) and Audited Demand Reduction adjusted down by the greater of (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets), or (Real-Time Demand Reduction Obligation plus Net Supply for any associated Net Supply Generator Assets). For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that as not received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Actual Load plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant), and the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant).

III.13.7.1.6. Self-Supplied FCA Resources.
Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) Forward Capacity Auction. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.
(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

### III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

### III.13.7.2.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

\[
\text{Charge Amount to Resource Exporting} = (\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}) \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid}
\]

\[
\text{Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located} = (\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}) \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid}
\]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.3.1.
III.13.7.2.3. **Intermittent Power Resources.**
An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. **Settlement Only Resources.**

III.13.7.2.4.1. **Non-Intermittent Settlement Only Resources.**
Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. **Intermittent Settlement Only Resources.**
Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. **Demand Resources.**

III.13.7.2.5.1. **Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.**
For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. **Monthly Capacity Payments for Real-Time Emergency Generation Resources.**
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources
A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources
A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply Generator Assets.
For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5,
of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.7.2.6. **Self-Supplied FCA Resources.**
Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. **Adjustments to Monthly Capacity Payments.**
Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. **Adjustments to Monthly Capacity Payments of Generating Capacity Resources.**

III.13.7.2.7.1.1. **Peak Energy Rents.**
Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. **Hourly PER Calculations.**
(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:
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Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]
Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.
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(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month (“Monthly PER”). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

\[
\text{PER Adjustment} = \min (i) \text{ the PER cap} \quad \text{or} \quad (ii) \text{ the Average Monthly PER} \times \text{PER Capacity Supply Obligation.}
\]

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties Adjustments.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the during any Obligation Month of a Capacity Commitment Period. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity
Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For each capacity resource that are partially or fully unavailable during a Shortage Event:

(a) The resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period will be compared to its EFORp Availability Score for the historical five-year period used to represent resource availability in establishing the Installed Capacity Requirement for the most recent Capacity Commitment Period.

(b) Positive deviations, in which the resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period is greater than its EFORp Availability Score for the historical five-year period, will result in additional payment to the resource equal to the positive difference multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period times 150%.

(c) Negative deviations, in which the resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period is less than its EFORp Availability Score for the historical five-year period, will result in a charge to the resource equal to the negative difference multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period times 150%.

(d) Settlement

a. All charges pursuant to Section III.13.7.2.1.2(c) will be collected in the first month’s non-hourly bills following the conclusion of each Capacity Commitment Period.

b. To the extent the aggregate charge amounts pursuant to Section III.13.7.2.1.2(c) equal or exceed the aggregate payment amounts pursuant to Section III.13.7.2.1.2(b), all payments pursuant to Section III.13.7.2.1.2(b) will also be paid in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period and any remainder will be credited to participants in proportion to their average monthly Capacity Load Obligation for the relevant Capacity Commitment Period in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period.
c. To the extent the aggregate charge amounts pursuant to Section III.13.7.2.1.2(c) are less than the aggregate payment amounts pursuant to Section III.13.7.2.1.2(b), all payments pursuant to Section III.13.7.2.1.2(b) will also be paid in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period and any under-funding will be charged to participants in proportion to their average monthly Capacity Load Obligation for the relevant Capacity Commitment Period in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period.

d. Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

\[ \text{Penalty} = \text{[Resource’s Annualized FCA Payment]} \times PF \times [1 - \text{Shortage Event Availability Score}] \]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource’s Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.
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(a) **Per Day.** In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource’s Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month.** The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, multiplied by the resource’s Capacity Supply Obligation multiplied by 12.

(b) **Force Majeure.** If a resource is subject to a Force Majeure event that results in an extended outage, the resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed 20% of its Annualized FCA Payment for that Capacity Commitment Period, provided i) the resource’s Lead Market Participant timely and accurately communicates the existence of the Force Majeure and the resource’s status to ISO-NE, and ii) the resource’s Lead Market Participant demonstrates diligence in repairing the resource consistent with Good Utility Practice.

III.13.7.2.7.1.4. **Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.**

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity-
Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.2, Section III.13.7.1.5.10.1) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.
In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.
In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource’s Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed.
For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO’s annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant’s total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.
b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.
Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.
Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.
For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource’s Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section...
III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. **Positive Monthly Capacity Variances.**

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource’s Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time
Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation
Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period.

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity’s Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone’s Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity’s annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Commitment Period from the calendar year prior to the start of the Capacity Commitment Period.
A load serving entity’s Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

### III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.
In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

### III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.
The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

### III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity’s Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the
results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights (“CTRs”) for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone’s Net Regional Clearing Price and absolute value of each Capacity Zone’s Capacity Load Obligations, as calculated in Section III.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and for Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.
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For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of:
(i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone’s portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) Connecticut Import Interface. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) NEMA/Boston Import Interface. Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.
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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) Import Constraints. The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) Export Constraints. The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.
(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.5. [Reserved.]

III.13.7.3.6. Specifically Allocated CTRs for Pool Planned Units.

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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.
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<table>
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<tr>
<th></th>
<th>Millstone 3</th>
<th>Seabrook</th>
<th>Stonybrook GT 1A</th>
<th>Stonybrook GT 1B</th>
<th>Stonybrook GT 1C</th>
<th>Stonybrook 2A</th>
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<th>Wyman 4</th>
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<th>Winter (MW)</th>
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<table>
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<tr>
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<th>Winter (%)</th>
<th>Summer (MW)</th>
<th>Winter (MW)</th>
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<td>11.551%</td>
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<td>1.0144%</td>
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<tr>
<td>Ipswich</td>
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<td>Marblehead</td>
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<td>Peabody</td>
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<td>3.9929%</td>
<td>6.3791%</td>
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</tbody>
</table>
This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

### III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.
SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN
NRG Amendment #2 – Section III.13.7 [Changes incremental to NRG Amendment #1 are shown in yellow highlight]

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period ("Obligation Month"), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource’s availability during any Shortage Events. EFORp Hours in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.


III.13.7.1.1. Generating Capacity Resources.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for
resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource’s availability during any **Shortage Events EFORp Hours** during the month.

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**III.13.7.1.1.1. Definition of Shortage Events EFORp Hours.**

EFORp Hours shall be the hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January.

(a) A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.
In an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone.

An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

### Shortage Event EFORp Hours Availability Score

For each Shortage Event EFORp Hour, the ISO shall calculate an EFORp Hour Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource’s hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource’s Shortage Event Availability Score and shall accumulate and average the hourly scores to calculate an annual EFORp Hour Availability Score for each resource.
III.13.7.1.1.2. Hourly Availability Scores.
The ISO shall calculate an availability score for each resource for each hour that is an EFORp hour contains any portion of a Shortage Event. A resource’s availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource’s available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource’s Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.
A resource’s available MW in each hour that contains any portion of a Shortage Event is an EFORp Hour shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource’s available MW in an hour exceed that resource’s CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource’s Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.
(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource’s metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource’s available MW in an hour shall not be reduced as a result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource’s available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource’s available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.
III.13.7.1.1.4. Availability Adjustments.

(a) A resource’s hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource’s Capacity Supply Obligation, if any, during each hour of the Shortage Event EFORp Hour may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event each EFORp Hour.

(b) A resource’s hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO’s annual maintenance scheduling process. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource’s hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event EFORp Hour as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event that is an EFORp Hour. If both of theses
criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource’s performance.

III.13.7.1.2. Import Capacity.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Event EFORp Hours as defined in Section III.13.7.1.1.1. An Import Capacity Resource’s Shortage Event EFORp Hour Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1, as appropriate). An Import Capacity Resource’s available MW in each hour that contains any portion of a Shortage Event is an EFORp Hour shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource’s available MW in the hour shall be zero.
(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource’s available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.
The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.13.7.1.3. Intermittent Power Resources.
The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.
A Non-Intermittent Settlement Only Resource’s Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in any Shortage Event EFORp hour shall be the resource’s metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.
The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.
III.13.7.1.5.1. Capacity Values of Demand Resources.
The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012 the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First through Seventh Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.
For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. For a Demand Resource that cleared in the
Forward Capacity Auction for any of the Capacity Commitment Periods beginning June 1, 2012 through the Capacity Commitment Period beginning in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply in a future Capacity Commitment Period, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset’s monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer’s load for the month will be the Demand Reduction Value for that portion of the output. No average avoided peak transmission and distribution losses shall be applied to Net Supply associated with a Demand Response Asset, Demand Response Resource, or Demand Response Capacity Resource.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is a quantity of reduced demand produced by a Demand Resource and is calculated pursuant to Section III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7 and III.13.7.1.5.8.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month.
III.13.7.1.5.4.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. **Winter Seasonal Demand Reduction Value.**
The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. **Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.**
Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to: (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Seasonal Peak Hours or (ii) the Seasonal DR Audit results if the Demand Reduction Value for the previous month was not calculated using Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) where there was no audit conducted in the month, the applicable previous seasonal Demand Reduction Value.

III.13.7.1.5.5.1. **Summer Seasonal Demand Reduction Value.**
The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.
III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its monthly Demand Reduction Values in the most recent months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. [Reserved.]

III.13.7.1.5.6.1. [Reserved.]

III.13.7.1.5.6.2. [Reserved.]

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.
Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous month’s Demand Reduction Value was calculated using Real-Time Demand Response Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Demand Response Event Hours. If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of June or December the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Demand Response Resource in that month.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand
Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.
An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one; or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. **Demand Reduction Values for Real-Time Emergency Generation Resources.** Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month.
If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to (i) the Demand Reduction Value established for the previous month if the previous months Demand Reduction Value was calculated using Real-Time Emergency Generation Event Hours or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month if the Demand Reduction Value for the previous month was not calculated using Real-Time Emergency Generation Event Hours. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of June or December, the Demand Reduction Value of that resource for those months shall be equal to (i) the first applicable seasonal audit, if conducted in that month, or (ii) the sum of the audit values of the assets mapped to the Real-Time Emergency Generation Resource in that month.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.
The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.
The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.
The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.


An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency...
Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Dispatch Zone in the hour.


Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Event EFORp Hours as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource’s Shortage Event EFORp Hour Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the
ability to reduce demand, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

### III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource’s available MW in each hour that contains any portion of a Shortage Eventis an EFORp Hour shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource’s available MW in an hour exceed that resource’s Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply Generator Asset, shall be reducted by the difference between the Real-Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset.

(a) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instructions where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than (the Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets) and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of (the resource’s Real-Time Demand Reduction Obligation plus the Net Supply for any associated available Net Supply Generator Assets) and the lesser of (the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Economic Maximum Limit for any associated available Net Supply Generator Assets), the resource’s Hourly Adjusted Audited Demand Reduction, or (the resource’s Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant).
(b) For a Demand Response Resource that reduces demand and is following Dispatch Instructions and for any associated Net Supply Generator Assets that are following Dispatch Instruction where the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is equal to Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets or (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets) or total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets is less than the Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply.

(c) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation plus any associated Net Supply is less than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply for the hour.

(d) For a Demand Response Resource that has reduced demand or any associated Net Supply Generator Assets that have been dispatch but are not responding to Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the total Desired Dispatch Point for the Demand Response Resource and the associated Net Supply Generator Assets, the available MW in an hour shall be the lesser of the resource’s Real-Time Demand Reduction Obligation plus any associated Net Supply and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) of thirty minutes or less, the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, and Actual Load) plus the sum of
the Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full-Reduction Time (adjusted for the Maximum Reduction and Economic Maximum Limit for any associated available Net Supply Generator Assets) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of (the lesser of (the resource’s Maximum Reduction, as submitted or redeclared by the Lead Market Participant, the resource’s Actual Load plus Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant) or the resource’s Hourly Adjusted Audited Demand Reduction) time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.

(g) For a Demand Response Resource that (i) is not reducing demand, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction.

A Demand Response Resource’s Adjusted Audited Demand Reduction shall be determined as follows. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5 of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-
Time Emergency Generation Asset’s output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction set equal to the resource’s Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{\text{(the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}}{\text{(the Offered Full Reduction Time adjusted for the Audited Demand Reduction))}} \times \min\left(\text{Audited Demand Reduction}, \left(\text{Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets}\right)\right)
\]

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets) shall have its Adjusted Audited Demand Reduction calculated as:

\[
\frac{\text{(the Offered Full Reduction Time adjusted for the Audited Demand Reduction)\)}}{\text{(the Audited Full Reduction Time adjusted for the (Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets))}} \times \min\left(\text{Audited Demand Reduction}, \left(\text{Maximum Reduction as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets}\right)\right)
\]

III.13.7.1.5.10.1.2 Hourly Adjusted Audited Demand Reduction.
The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

### III.13.7.1.5.10.2 Availability Adjustments

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response Capacity Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource’s hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource’s hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced reduction or scheduled reduction.

(i) A forced reduction can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced reduction. The forced reduction can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource.

(ii) A scheduled reduction must be submitted to the ISO at least 15 days ahead of the start of the reduction to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment. The scheduled
reduction cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response Capacity Resource. Scheduled reductions must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus Economic Maximum Limit for any associated available Net Supply Generator Assets) and Audited Demand Reduction adjusted down by the greater of (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets), or (Real-Time Demand Reduction Obligation plus Net Supply for any associated Net Supply Generator Assets). For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the Economic Maximum Limit of the Net Supply Generator Asset at the same location shall be reduced by the difference between the Real-Time Emergency Generation Asset’s output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that as not received a Dispatch Instruction to reduce its demand, the lesser of the resource’s Actual Load plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant), and the Audited Demand Reduction adjusted down by (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant).

III.13.7.1.6.  Self-Supplied FCA Resources.
Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.
Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.
Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource’s Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.
(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

**III.13.7.2.2. Import Capacity.**

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

**III.13.7.2.2.A. Export Capacity.**

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows *(for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments)*.

\[
\text{Charge Amount to Resource Exporting} = (\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}) \times \text{Cleared MWs of Export Bid or Administrative Export De-List Bid}
\]

\[
\text{Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located} = (\text{Capacity Clearing Price}_{\text{location of the interface}} - \text{Capacity Clearing Price}_{\text{location of the resource}}) \times \text{Cleared MWs of Export Bid or Administrative Export De-list Bid}
\]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.3.1.
III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.
For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4.1 Adjustment for Net Supply Generator Assets.

For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5,
of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

### III.13.7.2.6. Self-Supplied FCA Resources.
Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

### III.13.7.2.7. Adjustments to Monthly Capacity Payments.
Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

### III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

#### III.13.7.2.7.1.1. [Reserved] Peak Energy Rents.
Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

#### III.13.7.2.7.1.1.1. Hourly PER Calculations.
(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:
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Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor].

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra-low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints.

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.
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(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that
month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy
unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12
months prior to the Obligation Month. The PER deduction for each resource shall be calculated as
follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity
Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any
other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same
Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource’s
location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than
zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation
or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-
Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply
Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation
calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties Adjustments.
Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the
beginning of the during any Obligation Month of a Capacity Commitment Period. The penalty will be
based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b) or as described in
Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity
Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For each capacity resource that are partially or fully unavailable during a Shortage Event:

(a) The resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period will be compared to its EFORp Availability Score for the historical five-year period used to represent resource availability in establishing the Installed Capacity Requirement for the most recent Capacity Commitment Period.

(b) Positive deviations, in which the resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period is greater than its EFORp Availability Score for the historical five-year period, will result in additional payment to the resource equal to the positive difference multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period times 150%.

(c) Negative deviations, in which the resource’s annual EFORp Availability Score for the most recent Capacity Commitment Period is less than its EFORp Availability Score for the historical five-year period, will result in a charge to the resource equal to the negative difference multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.8) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period times 150%.

(d) Settlement

a. All charges pursuant to Section III.13.7.2.1.2(c) will be collected in the first month’s non-hourly bills following the conclusion of each Capacity Commitment Period.

b. To the extent the aggregate charge amounts pursuant to Section III.13.7.2.1.2(c) equal or exceed the aggregate payment amounts pursuant to Section III.13.7.2.1.2(b), all payments pursuant to Section III.13.7.2.1.2(b) will also be paid in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period and any remainder will be credited to participants in proportion to their average Capacity Load Obligation for the relevant Capacity Commitment Period in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period.
c. To the extent the aggregate charge amounts pursuant to Section III.13.7.2.1.2(c) are less than the aggregate payment amounts pursuant to Section III.13.7.2.1.2(b), all payments pursuant to Section III.13.7.2.1.2(b) will also be paid in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period and any under-funding will be charged to participants in proportion to their average Capacity Load Obligation for the relevant Capacity Commitment Period in the first month’s non-hourly bills following the conclusion of the Capacity Commitment Period.

d. Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

\[ \text{Penalty} = (\text{Resource’s Annualized FCA Payment}) \times \text{PF} \times (1 - \text{Shortage Event Availability Score}) \]

Where:

- Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) multiplied by the resource’s Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

- PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.
(a) **Per Day.** In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource’s Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month.** The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period.** In determining the availability penalties for the Obligation Month, a resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, multiplied by the resource’s Capacity Supply Obligation multiplied by 12.

(b) **Force Majeure.** If a resource is subject to a Force Majeure event that results in an extended outage, the resource’s cumulative availability penalties for a Capacity Commitment Period may not exceed 20% of its Annualized FCA Payment for that Capacity Commitment Period, provided i) the resource’s Lead Market Participant timely and accurately communicates the existence of the Force Majeure and the resource’s status to ISO-NE, and ii) the resource’s Lead Market Participant demonstrates diligence in repairing the resource consistent with Good Utility Practice.

III.13.7.2.7.1.4. **Availability Credits for Capacity Demand Response Capacity Resources, Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.**

On a monthly basis, penalties received from unavailable resources shall be redistributed to Demand Response Capacity Resources, Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity-
Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.2, Section III.13.7.1.5.10.1) on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro-rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.
In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.
In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the following:

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource’s Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed.
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For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b) for any amount that was unavailable due to an outage approved in the ISO’s annual maintenance scheduling process.

(c) Except as specified in Section III.13.7.2.7.2.1, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

A Market Participant’s total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource’s Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

a) No penalty will be assessed if the applicable external interface is fully loaded and the energy from an External Transaction that would otherwise be requested cannot flow. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.
b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.
Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.
Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.
Demand Response Capacity Resources shall be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.
For each month, the Monthly Capacity Variance of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be calculated by subtracting the Demand Resource’s Capacity Supply Obligation for the month from the Demand Resource’s monthly Capacity Value. If a Demand Resource’s Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource’s Monthly Capacity Variance is a negative value, the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource shall be set according to the Capacity Clearing Price applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), 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 applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section.
III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource’s Monthly Capacity Variance is a positive value, then the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period, or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, then the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Real-Time Emergency Generation, Real-Time Demand Response, On-Peak and Seasonal Peak Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month in the Capacity Zone where the Demand Resource or Real-Time
Emergency Generation Resource is located is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone.

III.13.7.2.7.5.4. **Determination of Net Demand Resource Performance Penalties and Demand Resource Performance Incentives.**

Demand Resource Performance Penalties and Demand Resource Performance Incentives shall be determined for each Capacity Zone as follows: if the sum of the Demand Resource Performance Penalties in a month in a Capacity Zone is less than the sum of the Demand Resource Performance Incentives in the same month in that Capacity Zone, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total amount of the Demand Resource Performance Penalties in the same month in that Capacity Zone.

The total of the Demand Resource Performance Incentives in a month in a Capacity Zone cannot exceed the total of the Demand Resource Performance Penalties in the same month in that Capacity Zone. If the total Demand Resource Performance Penalties in a month in a Capacity Zone exceeds the total Demand Resource Performance Incentives in the same month in that Capacity Zone, the difference shall not be collected from load serving entities in that Capacity Zone (the ultimate purchaser of capacity).

III.13.7.2.7.6. **Self-Supplied FCA Resources.**

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. **Charges to Market Participants with Capacity Load Obligations.**

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation
Bilaterals), less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period to the system-wide sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period.
The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with pumping of pumped hydro generators, if the resource was pumping; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; and transmission losses associated with delivery of energy over the Control Area tie lines.

A load serving entity’s Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone’s Capacity Requirement as calculated above and (ii) the ratio of the sum of the load serving entity’s annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities’ annual coincident contributions to the system-wide annual peak load in that Capacity Commitment Period from the calendar year prior to the start of the Capacity Commitment Period.
A load serving entity’s Capacity Load Obligation shall be its Capacity Requirement, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supply FCA Resource designations. A Capacity Load Obligation can be a positive or negative value. A Market Participant that is not a load serving entity shall have a Capacity Load Obligation equal to the net obligation resulting from Capacity Load Obligation Bilaterals, HQICC, and Self-Supply FCA Resource designations.

A Demand Resource's Demand Reduction Value will not be reconstituted into the load of the Demand Resource for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

### III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

### III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

### III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity’s Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the
results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.3.3.

III.13.7.3.3. Capacity Transfer Rights.

III.13.7.3.3.1. Definition and Payments to Holders of Capacity Transfer Rights.

The ISO shall create Capacity Transfer Rights (“CTRs”) for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone’s Net Regional Clearing Price and absolute value of each Capacity Zone’s Capacity Load Obligations, as calculated in Section III.13.7.3.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER and Demand Resource Performance Penalties net of Demand Resource Performance Incentives.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.
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For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supply FCA Resources.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) for 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. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone’s portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2.   Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a)  Connecticut Import Interface. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b)  NEMA/Boston Import Interface. Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.
(c) **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. Each municipal utility entitlement holder of a resource constructed as a Pool-Planned Unit in Maine shall receive specifically allocated CTRs across the Maine Export Interface equal to the applicable seasonal claimed capability of its ownership entitlements in such unit as described in Section III.13.7.3.3.6. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

**III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.**

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

**III.13.7.3.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.**

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.
(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.5. [Reserved.]

III.13.7.3.6. Specifically Allocated CTRs for Pool Planned Units.
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 an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.
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<th>Millstone 3</th>
<th>Seabrook</th>
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<th>Stonybrook GT 1B</th>
<th>Stonybrook GT 1C</th>
<th>Stonybrook 2A</th>
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<th>Wyman 4</th>
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<td>1244.275</td>
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<th>Winter %</th>
<th>Summer (MW)</th>
<th>Winter (MW)</th>
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<td>1.1124%</td>
<td>8.4569%</td>
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<tr>
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This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant (“WRC”) any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.
TO: NEPOOL Participants Committee  
DATE: November 27, 2013

FROM: Joel Gordon, PSEG Energy Resources & Trade LLC

RE: Proposed Amendment MR1, III.13.2.4 Forward Capacity Auction Starting Price.

III.13.2.4. Forward Capacity Auction Starting Price.
The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 shall be $22/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

BACKGROUND:
For FCA 7 the starting price of the auction was $15. Using the existing escalation formula in the tariff, the starting price for FCA 8 will be $15.82 kw-month. Using an assumed 4% inflator for FCA9 would result in a starting price of $16.45. It is PSEG’s belief that the starting price of the auction for FCA 9, is not sufficiently high enough to satisfy investment requirements for certain types of resources, such as combustion turbines, to justify participation in the FCA.

Specifically, the Offer Review Trigger Price (Net Cost of New Entry) proposed by ISO-NE beginning FCA 9 for a Combustion Turbine is $13.424 kw-month. This is the price, as determined by Brattle and supported by the ISO, which is required by an investor for 20 consecutive years in order to justify the investment in a fast start combustion turbine. When the ORTP concept was first implemented the ORPT for a CT was $10 kw-mo.

- Thus for FCA8 the starting price of $15.82 is a 58% premium over the ORTP.
  - Using this ratio for FCA9, the starting price for FCA 9 should be just over $21 kw-mo.
- Without a change for FCA 9, the starting price will provide slightly over a 20% margin in headroom over the 20 year long run revenue requirement for the resource, down from the 50% margin when this rule went into effect.

The current starting price also fails to take into consideration the significant increase in risk that Performance Incentives imposes on capacity resources as well as the additional cost imposed by the new Financial Assurance requirement. Thus, any resource participating in the FCA will also need to add to its offer an additional risk premium to account for the potential significant downside risk associated with PI and other real costs imposed by the design.

- And while PI favors fast start combustion turbines based upon the five minute energy/reserve test for determining penalties and payments, the resource that can best provide that service will be held out from participation because the starting price of the auction is too low.
  - Investors will significantly discount the upside and focus on the potential downside when determining risk premiums, adding onto the Net Cone value additional PI based costs.

Finally, it should be noted that this is only the starting price of the auction. As is widely acknowledged, setting the starting price high should have little outcome on the clearing price since competition will discipline new entry; However, setting the price too low, as is the current $15 kw-month starting price, will prevent new resources from even coming to the fore.
SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN
NRG Amendment #3 – Part 1 of 5, Sections III.13.1.2.3 and III.13.1.2.4

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.
For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource’s Lead Market Participant of the resource’s summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.
A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period
associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold. The Dynamic De-List Bid Threshold shall be equal to 80% of the Offer Review Trigger Price for a Combustion Turbine as specified in Section III.A.21.1.1.

III.13.1.2.3.1.1. Static De-List Bids. An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation the capacity market at prices at or above $1.00/kW-month the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to
three price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b) or as otherwise directed by the Commission pursuant to Section III.13.1.2.3.2.1.1.

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource’s full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b) or as otherwise directed by the Commission pursuant to Section III.13.1.2.3.2.1.1. A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the
Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.
An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above $1.00/kW-month the Dynamic Delist Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall establish a cap on the resource’s price participation in be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b) or as otherwise directed by the Commission pursuant to Section III.13.1.2.3.2.1.1.

III.13.1.2.3.1.4. Administrative Export De-List Bids.
An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource’s full summer Qualified Capacity. Unless
reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.
A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.
The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.
Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist 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.

Reserved.

Internal Market Monitor Review.
The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing 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 de-list 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 de-listing of each individual asset in preferred de-list 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 bids 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 bids 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 Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into approved for use as a cap in the Forward Capacity Auction as described in Section III.13.2.3.2(b) or as otherwise directed by the Commission pursuant to Section III.13.1.2.3.2.1.1. If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted
composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

### III.13.1.2.3.2.
Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

#### III.13.1.2.3.2.1.
Static De-List Bids, Export Bids Above $1.00/kW-month \(\text{Dynamic Delist Bid Threshold}\), and Permanent De-List Bids Above $1.00/kW-month \(\text{Dynamic Delist Bid Threshold}\).

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic Delist Bid Threshold $1.00/kW-month, and each Permanent De-List Bid above the Dynamic Delist Bid Threshold $1.00/kW-month to determine whether the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward net average long-run costs (as determined pursuant to Section III.13.1.2.3.2.1.1) and opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.2). Sufficient documentation and information must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs and the reasonableness of the estimates and adjustments of to represent costs that would otherwise be avoided if the resource were required to meet the obligations of a listed resource, and shall be subject to audit upon request by the ISO.

#### III.13.1.2.3.2.1.1.
Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate.

#### III.13.1.2.3.2.1.1.1.
Review of Permanent De-List Bids and Export Bids.

In the case of a Permanent De-List Bid or an Export Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going forward net average long-run and opportunity costs, then the bid shall be approved for use as a cap in entered into the
Forward Capacity Auction as described in Section III.13.2.3.2(b) or as otherwise directed by the Commission pursuant to Section III.13.1.2.3.2.1.1. If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going-forward average long-run and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going-forward average long-run costs and opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going-forward average long-run costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be approved for use as a cap in the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month the Dynamic Delist Bid Threshold.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource’s net risk-adjusted going-forward average long-run and opportunity costs, then the bid shall be entered into approved for use as a cap in the Forward Capacity Auction as described in Section III.13.2.3.2(b) or as otherwise directed by the Commission; provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the
resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than $1.00/kW-month the Dynamic Delist Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic Delist Bid Threshold $1.00/kW-month.

(b) In the case of a Static De-List Bid, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource’s net risk-adjusted going forward average long-run and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource’s net risk-adjusted going forward average long-run costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource’s net risk-adjusted going forward average long-run costs and opportunity costs as determined by the Internal Market Monitor and greater than $1.00/kW-month the Dynamic Delist Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor’s determinations regarding the resource’s net risk-adjusted going forward average long-run costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month the Dynamic Delist Bid Threshold.
III.13.1.2.3.2.1.2. Net Risk-Adjusted Going Forward Average Long-Run Costs.

A Static De-List Bid, Export Bid above $1.00/kW-month the Dynamic Delist Bid Threshold, or Permanent De-List Bid above $1.00/kW-month the Dynamic Delist Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource’s net risk-adjusted going-forward average long-run costs based on a review of the data submitted in the following formula by the resource’s Lead Market Participant. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available, adjusted for inflation and anticipated incremental capital and operating expenses associated with the relevant Capacity Commitment Period.

\[
\frac{GFC}{(CQ_{\text{Summer}}, \text{kw}) \times (12, \text{months})} + \left[ RF \right] - \left[ (IMR - PER) \right] \times \text{InfIndex}
\]

Where:

- GFC = annual going-forward costs, in dollars. These are costs 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 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 should be net of anticipated energy and ancillary service revenues are not to be included. Service of debt, depreciation and amortization, equity return, is not a going-forward cost. Staffing, maintenance, capital expenses, taxes, insurance and other normal expenses that would be avoided only in the absence of the resource in support of meeting the obligations 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 Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall may be reported to the ISO using the spreadsheet format provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and
measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

\[
CQ_{\text{summer}}\text{kW} = \text{capacity seeking to de-list in kW}. \text{ In no case shall this value exceed the resource’s summer Qualified Capacity.}
\]

\[
RF = \text{risk factor, in dollars. This value shall be calculated using the following formula:}
\]

\[
RF = [(RPC \times EFoRd) + (P \times (\text{Forward Capacity Auction Starting Price} - \text{AFCAP}) \times 12,\text{months})] \times CQ_{\text{summer}}\text{kW}.
\]

Provided: If \( EFoRd \) is greater than 0.40 then 0.40 shall be used, and if \( EFoRd \) is less than 0.05 then 0.05 shall be used.

\( EFoRd \) shall be for the corresponding period used in quantifying going-forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

\( RPC = \text{replacement power costs rate, in dollars/kW}. \text{ As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit’s daily price to the resource’s Real-Time nodal price. For each hour that the resource’s nodal price exceeds the PER Proxy Unit’s daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit’s daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.}

\( P = \text{Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period}. \text{ This estimate shall be no greater than the } EFoRd \text{ of the resource for}
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the corresponding period used in quantifying going-forward costs, and in no case greater than 0.40. The
Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward
Capacity Auction clearing prices in the resource’s Capacity Zone.

AA = availability adjustment. AA = (1–EFORd)

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05
shall be used.

EFORd shall be for the corresponding period used in quantifying going-forward costs and shall be

calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the
submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in
the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the
case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data
representing the cumulative actual 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 Existing Generating Capacity Resource’s total ISO market revenues. In the case of
a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that
the resource will not be participating in the energy and ancillary services markets during the Capacity
Commitment Period, this value shall be $0.00. As soon as practicable, the resource’s total ISO market
revenues used in this calculation shall be calculated by the ISO and available to the Lead Market
Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be
calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent
three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for.
each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.

\[ \text{InfIndex} = \text{inflation index, } \text{InfIndex} = (1 + i)^t. \]

Where: \( i \) is the most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above $1.00/kW-month the Dynamic Delist Bid Threshold, or Permanent De-List Bid above $1.00/kW-month the Dynamic Delist Bid Threshold has risk-based or other opportunity costs that support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward average long-run costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, 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. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into approved for use as a cap in the Forward Capacity Auction as described in Section III.13.2.3.2(b) or as otherwise directed by the Commission.

III.13.1.2.3.2.2. [Reserved.]
III.13.1.2.3.2.3. **Administrative Export De-List Bids.**
The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. **Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.**
A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. **Incremental Capital Expenditure Recovery Schedule.**
Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

<table>
<thead>
<tr>
<th>Age of Existing Resource (years)</th>
<th>Remaining Life (years)</th>
<th>Annual Rate of Capital Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 to 5</td>
<td>30</td>
<td>0.106</td>
</tr>
<tr>
<td>6 to 10</td>
<td>25</td>
<td>0.110</td>
</tr>
<tr>
<td>11 to 15</td>
<td>20</td>
<td>0.117</td>
</tr>
<tr>
<td>16 to 20</td>
<td>15</td>
<td>0.131</td>
</tr>
<tr>
<td>21 to 25</td>
<td>10</td>
<td>0.163</td>
</tr>
</tbody>
</table>
A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

\[
\frac{\text{Cost Of Capital}}{(1-\frac{1}{1+\text{Cost Of Capital}})^{\text{Remaining Life}}}
\]

Where:
Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.
No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into represent a cap on the resource’s price participation in the Forward Capacity Auction as described in Section III.13.2.3.2(b) or as otherwise directed by the Commission. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor’s review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource’s net risk-adjusted going-forward average long-run costs and
opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.
III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above $1.00/kW-month the Dynamic Delist Bid Threshold or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.
NRG Amendment #3 – Part 3 of 5, Section III.13.2.3.2

III.13.2.3.2. Step 2: Compilation of Offers and Bids.
The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and
New Demand Resources.

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.
iii) Let the Start-of-Round Price and End-of-Round Price for a given round be \( P_S \) and \( P_E \), respectively. Let the \( m \) prices \( (1 \leq m \leq 5) \) submitted by a Project Sponsor for a modeled Capacity Zone be \( p_1, p_2, ..., p_m \), where \( P_S > p_1 > p_2 > ... > p_m \geq P_E \), and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be \( q_1, q_2, ..., q_m \). Then the Project Sponsor’s supply curve, for all prices strictly less than \( P_S \) but greater than or equal to \( P_E \), shall be taken to be:

\[
S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\vdots & \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}
\]

where, in the first round, \( q_0 \) is the resource’s full FCA Qualified Capacity and, in subsequent rounds, \( q_0 \) is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically authorize the resource’s Lead Market Participant to submit a bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the
Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) Dynamic De-List Bids. In any round of the Forward Capacity Auction in which prices are below $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of
that round’s relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

Repowering. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the
qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing
the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.
NRG Amendment #3 – Part 4 of 5, Section III.13.2.5.2.5.1

III.13.2.5.2.5.1.  Compensation for Bids Rejected for Reliability Reasons.

(a)(i)  In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.

(a)(ii)  A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i)  In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability. If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then theExisting Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific
Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).
NRG Amendment #3 – Part 5 of 5, Section III.13.8

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward 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;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;
(vii) the Internal Market Monitor’s determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor’s determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource’s long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor’s determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids based on the Internal Market Monitor review and the resource’s net risk-adjusted going-forward average long-run costs and opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO’s submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO’s submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward
Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO’s submission of the informational filing, the Commission does issue an order modifying one or more of the ISO’s determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.
(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO’s filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. [Reserved.]

III.13.8.4. [Reserved.]
REVISED MAIN MOTION #2
AGENDA ITEM 10
FCM PI FINANCIAL ASSURANCE POLICY CHANGES

The following revised form of resolution may be used for Participants Committee action on the
FA Changes related to the PI Proposal:

RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO-NE Financial Assurance Policy to establish financial assurance requirements under the FCM Performance Incentives (PI) Proposal (FA Changes), as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with [any changes agreed to at this meeting and] such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve; it being understood that a vote in favor of this resolution reflects solely support for the FA Changes, as appropriate, if and only if the FCM PI Proposal is approved and implemented as proposed by the ISO, and is without prejudice to any position taken by a Participant(s) on the underlying FCM PI Proposal, and with the further understanding that the FA Changes and any proposed revisions thereto shall be re-presented to NEPOOL for subsequent consideration in the Participants Process if the Commission requires changes to the underlying FCM PI Proposal.
EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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ATTACHMENT 1 - SECURITY AGREEMENT
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VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKET

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auctions, reconfiguration auctions or Capacity Supply Obligation Bilaterals for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. Commercial Capacity FCM Delivery Financial Assurance

A Designated FCM Participant must include FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy on the first Business Day of each month of a Capacity Commitment Period. FCM Delivery Financial Assurance is calculated according to the following formula:

\[
\text{FCM Delivery Financial Assurance} = \text{MCC} + \text{CSOFADFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{VCWAP}), 0.1] \times \text{SF} \times \text{DF}
\]

Where:

\(\text{MCC}\) (monthly capacity charge) equals FCM charges (negative Monthly Capacity Payments) incurred in previous months, but not yet paid. The MCC is estimated on the first business day of the current delivery month. The actual settled MCC value replaces the MCC estimate when the actual settlement is complete.

\(\text{DFAMW}\) (delivery financial assurance MW) \(\text{CSOF}\) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant’s portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated \(\text{CSOFADFAMW}\) is less than zero, then the \(\text{CSOFADFAMW}\) will be set equal to zero.
PE (potential exposure) is a monthly value calculated for the Designated FCM Participant’s portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to the those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires. the Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price, both associated with the Forward Capacity Auction corresponding to the instant Capacity Commitment Period.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

VWCAP (volume weighted average performance) is the capacity weighted average performance of the Designated FCM
Participant’s portfolio. For each resource in the Designated FCM Participant’s portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1 and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource’s Capacity Supply Obligation shall be multiplied by the average performance of the resource during Capacity Scarcity Conditions in the rolling three year period immediately preceding the instant delivery month. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant’s CSOFA DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource’s Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating Resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating Resources shall equal 0.85; the temporary average performance for oil-fired steam generating Resources shall equal 0.65; the temporary average performance for all other resources (Demand Resources, Import Capacity Resources backed by an external control area, nuclear-powered generating Resources, and renewable generating Resources) shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

- June 2.000;
- December and July 1.732;
- January and August 1.414;
All other months 1.000.

DF (discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; for the Capacity Commitment Period beginning on June 1, 2021 and ending on May 31, 2022 and thereafter, DF shall equal 1.00.

offering the capacity of a Resource that (i) has been declared commercial and had its capacity rating verified by the ISO and (ii) has not elected to be treated as, a New Generating Capacity Resource in connection with new investment in that Resource pursuant to Market Rule 1 (“Commercial Capacity”) into an upcoming Forward Capacity Auction or providing Commercial Capacity during any Capacity Commitment Period must generally comply with the requirements of the ISO New England Financial Assurance Policy with respect to such transactions; provided, however, that for any Resource representing Commercial Capacity that has been permitted to retire at the end of a current Capacity Commitment Period under Section I.3.9 of the ISO Tariff or any similar provision and whose obligation to provide all of such Commercial Capacity during that Capacity Commitment Period has not been transferred to another Resource, the Designated FCM Participant for such Resource shall include in the calculation of its Financial Assurance Requirement under the Policy, beginning at least five (5) Business Days prior to the applicable Capacity Commitment Period, an amount equal to two and one half (2.5) times the monthly FCM payment due to such Designated FCM Participant with respect to such Commercial Capacity during the applicable Capacity Commitment Period.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit
A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the “FCM Deposit”).

2. **Non-Commercial Capacity in Forward Capacity Auctions**

A Designated FCM Participant offering Non-Commercial Capacity into a Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount equal to the difference between the Forward Capacity Auction Starting Price times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

\[
\text{Non-Commercial Capacity Financial Assurance Amount} = \text{NCC} \times \text{NCCFCAS} \times \text{Multiplier}
\]

Where:

- \( \text{NCC} \) = the Capacity Supply Obligation awarded in the Forward Capacity Auction minus any Commercial Capacity
- \( \text{NCCFCAS} \) = the applicable capacity price from the Forward Capacity Auction in which the Capacity Supply Obligation was awarded
- Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.
In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

3. **Return of Non-Commercial Capacity Financial Assurance**

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in any Forward Capacity Auction becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above.

4. **Credit Test Percentage Consequences for Provisional Members**

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant’s Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. **FCM Capacity Charge Requirements**
The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the Estimated Net Regional Clearing Price (ENRCP) for the applicable Capacity Zone. For purposes of this calculation, the Estimated Capacity Load Obligation shall be the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource Designations for the applicable month. For purposes of this calculation, the ENRCP for a Capacity Zone will be calculated as follows: (i) If the latest available Net Regional Clearing Price for the Capacity Zone is for a month that is within the current Capacity Commitment Period, then the ENRCP shall be the Net Regional Clearing Price for the latest available month for the applicable Capacity Zone. (ii) If the latest available Net Regional Clearing Price for the Capacity Zone is for a month that is within the immediately preceding Capacity Commitment Period, then the ENRCP shall be the Net Regional Clearing Price for the latest available month for the applicable Capacity Zone, adjusted by the quotient of the Capacity Clearing Price for the applicable Capacity Commitment Period divided by the Capacity Clearing Price for the immediately preceding Capacity Commitment Period. If for the purpose of the calculation in this section (ii) the Capacity Clearing Price is not available from the immediately preceding Capacity Commitment Period, then the ENRCP to be used in the calculation of the FCM Capacity Charge Requirements shall be the Capacity Clearing Price for the applicable Capacity Commitment Period.

D. Loss of Capacity and Forfeiture of Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will
be assessed a default charge of one percent (1%) of its total FCM Financial Assurance Requirements, Non-Commercial Capacity Financial Assurance Amount, at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the “Non-Commercial Capacity Cure Period”), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the financial assurance provided by that Designated FCM Participant with respect to terminated Capacity Supply Obligations associated with Non-Commercial Capacity and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant’s failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant’s Capacity Supply Obligation associated with Non-Commercial Capacity is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount of the financial assurance provided by such Designated FCM Participant with respect to such terminated Non-Commercial Capacity Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant’s positive Market Credit...
Limit) by such Designated FCM Participant with respect to such terminated Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a “Composite FCM Transaction”), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the additional financial assurance required with respect to its Resources included in that Composite FCM Transaction, determined as follows:

1. the FCM Financial Assurance Requirements, if any, for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. if any Resource in the Composite FCM Transaction has been permitted to retire at the end of a current Capacity Commitment Period under Section I.3.9 of the ISO Tariff or any similar provision, the FCM Financial Assurance Requirements under Section VII.A with respect to that Resource will expire when that Resource is no longer responsible for providing capacity;

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the FCM Financial Assurance Requirements under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount additional financial assurance provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be returned by the ISO to such Designated FCM Participant under recalculated according to Section VII.B.3 when-as the corresponding Resource has...
been declared commercial and successfully verified for its capacity ratings by the ISO or has otherwise become a Resource meeting the definition of Commercial Capacity above and all of the other requirements of Section VII.B.3 have been satisfied; and

5. in the event that for purposes of Section VII.D, any termination of the Capacity Supply Obligation is terminated, Section VII.D Non-Commercial Capacity shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the period including the earliest month that has not yet been billed and each of the eleven months immediately thereafter, the sum of that Designated FCM Participant’s net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant’s net FCM revenue results in a credit are disregarded (i.e., the net credits from
such months are not used to reduce the amount described in this subsection (a)). The
amount described in this subsection (a), if any, will increase the Designated FCM
Participant’s FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a)
above and that is included in a Capacity Commitment Period for which a Forward
Capacity Auction has been conducted, the sum of that Designated FCM Participant’s net
monthly FCM charges for each month in which the net FCM revenue results in a charge.
For this period, the sum of such charges may be offset by net credits from months in
which the net FCM revenue results in a credit, but in no case will the amount described in
this subsection (b) be less than zero. The amount described in this subsection (b), if any,
will increase the Designated FCM Participant’s FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined
by accounting for all charges and credits, \textit{exclusive of any accrued Capacity
Performance Payments on positions currently or previously held}, related to the purchase
or sale of Capacity Supply Obligations in the Forward Capacity Market for the month,
including those resulting from the Forward Capacity Auction, any applicable
reconfiguration auctions, and any applicable Capacity Supply Obligation Bilaterals.
However, such charges and credits shall not include un\textit{cleared offers to supply capacity}
in any applicable reconfiguration auctions or any applicable Capacity Supply Obligation
Bilaterals. Upon the completion of each reconfiguration auction, the amount to be
included in the calculation of any FCM Financial Assurance Requirements of that
Designated FCM Participant shall be adjusted to reflect the cleared MW at the zonal
clearing price for all activity in that reconfiguration auction.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals
A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a
Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial
Assurance Requirements under the ISO New England Financial Assurance Policy, prior
to the close of the period for submission of that Capacity Supply Obligation Bilateral,
amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated
FCM Participant fails to provide the required additional financial assurance for its
Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the
Designated FCM Participant’s request to transfer a Capacity Supply Obligation in a
Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance Credits for Capacity Supply Obligations

If in none of the twelve months described in Section VII.F.1 (a) the net monthly FCM revenue results in a charge to that Designated FCM Participant, then the Designated FCM Participant’s FCM Financial Assurance Requirements will be reduced by the sum of net credits for any months prior to and including the current month in which the net FCM revenue results in a credit to that Designated FCM Participant and that have not yet been invoiced.
To: Budget and Finance Subcommittee
From: Marc Montalvo, Director Enterprise Risk Management
Date: November 25, 2013
Subject: FCM PI Financial Assurance

The following is an update to the November 18, 2013 design memo presented to the Budget and Finance Committee updated to reflect changes to the tariff language that address questions raised in the meeting. Also, the examples have been augmented to include cases in which resources have different capacity prices and a resource has elected a multi-year price.

Background

1. Forward Capacity Market Performance Incentives (FCM PI) design introduces the possibility that resources with capacity supply obligations will have obligations (owe money) to the market.

2. All obligations are collateralized through the posting of financial assurance under the ISO Financial Assurance Policy (FAP).

3. The goal of the FAP is to ensure that there is sufficient cash available for clearing the market each day and to cover a participant’s obligations in case of default.

4. As a general matter, Financial Assurance (FA) requirements are established to cover extreme loss scenarios (at least 99% not to exceed).

General Approach

A Market Participant with a Capacity Supply Obligation (CSO) will add FCM Delivery FA to its total FA requirements calculation. FCM Delivery FA is constructed to cover three types of risk: (1) payment of obligations already incurred in a past delivery month; (2) exposure to payment obligations arising from the pay-for-performance penalty associated with CSOs in the current delivery month; and
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(3) the ongoing exposure to obligations that may accrue against a CSO position post default due to the inability of the ISO to liquidate defaulted positions.

Design Components

- To protect against participant default in the current month, FA will equal the monthly stop loss for single asset portfolio.
- For a portfolio with multiple resources, to protect against participant default in the current month, FA will be a function of a value referred to as the Capacity Weighted Average Performance (CWAP), which is designed to capture the diversification benefits of a portfolio.
- Given the seasonal nature of scarcity conditions, we divide the capacity commitment period into three seasons: four summer months, three winter months and five shoulder months.
- The average system-wide balancing ratios and CWAP values for each resource will be calculated during system-wide Capacity Scarcity Condition using data from three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period. Until actual data become available, a set of predefined values will be used.
- The current month FA calculation will be adjusted by a scaling factor to capture liquidation risk. The scaling factor captures how many risky (summer or winter) months remain in the seasonal period. Due to this scaling factor, the total financial assurance for a given capacity supply obligation may exceed the monthly stop loss.
- Since the amount of FA held is a direct function of the monthly stop loss for the current delivery month, the addition of net daily financial assurance is less important. To simplify the financial assurance calculation, we have eliminated the net daily FA in the financial assurance calculation component from the design proposal.
- The net capacity charges from a completed delivery month incurred but not yet paid is added to the financial assurance requirement until the invoice is fully paid.
- A stop loss flag is used to track if a resource has reached its annual performance stop loss. Once a resource hits its annual stop loss, it is excluded from the FA calculation.

Notations and Calculations

We have adopted an n-1 contingency in the FCM PI financial assurance calculation. Namely, the capacity weighted average performance is calculated assuming that the largest resource in the portfolio is unavailable during the whole period of scarcity condition and the rest of resources perform consistent with average historical performance under the past three year’s of scarcity conditions.

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1 The amount of FCM Delivery FA held in any month will reflect exposure to the number of months remaining in the period. ISO is proposing that the annual commitment period be broken into seasonal sub-periods that reflect the differing exposure to scarcity events.
Exposure to capacity market obligations (net penalties) is a function of the following parameters:

i. Annual stop loss flag (SLF, 0 or 1)\(^2\)

ii. The mix of resources in the portfolio, i.e., Average Performance (AP)\(^3\) under capacity scarcity conditions, number of resources (n) in the portfolio, capacity supply obligation for each resource. Total capacity supply obligation of a portfolio (DFAMW) is the summation of capacity supply obligation of each individual resource excluding resources that have reached their annual stop loss. If the calculated DFAMW is less than zero, then DFAMW is set equal to zero.

\[ DFAMW = \max \left( \sum_{i=1}^{n} \max(DFAMW(i), 0) \right), \text{ where } SLF(i) = 0. \]

The capacity weighted average performance (CWAP) of a portfolio is calculated (1) excluding the resources that have reached their annual stop losses; and (2) assuming that the remaining largest asset (m) in the portfolio is not available.

\[ CWAP = \sum_{i=1}^{n} DFAMW(i) \times \frac{AP(i)}{DFAMW}, \text{ where } SLF(i) = 0 \text{ and } i \neq m \]

iii. average balancing ratio (ABR)\(^4\)

iv. monthly Potential Exposure (PE, $/MW)\(^5\)

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\(^2\) The annual stop loss flag tracks if the performance payment of a resource has reached its annual stop loss. Once a resource hits its annual stop-loss limit, it is waived from its future financial obligation in the remaining capacity commitment period.

\(^3\) Average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Condition divided by the product of the resource’s Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period. For monthly FA, the three groups of months correspond to summer, winter and shoulder months. Until data exists to calculate this number, the average performance for gas-fired generating Resources shall equal 0.90; the average performance for coal-fired generating Resources shall equal 0.85; the average performance for oil-fired generating Resources shall equal 0.65; the average performance for Demand Resources, Import Capacity Resources backed by an external control area, nuclear-powered generating Resources, and renewable generating Resources shall equal 1.00. These values are based on data presented in *Assessment of the Impact of ISO-NE’s Proposed Forward Capacity Market Performance Incentives*, Analysis Group, September 2013. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values each year until all three years reflect actual data.

\(^4\) The average balancing ratios are calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period. Three separate groups of months are used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the ABR for June through September shall equal 0.90; the ABR for December through February shall equal 0.70; and the the ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant groups of months will replace the temporary ABR values each year until all three years reflect actual data.
v. Month specific scaling factor (SF)\(^6\)

vi. Discount Factor (DF)\(^7\)

The monthly Financial Assurance Requirement is given by the following expression:

\[
[3] \quad \text{FA} = \text{MCC} + \text{DFAMW} \times \text{PE} \times (\text{MAX}(\text{ABR} - \text{CWAP}, 0.1)) \times \text{SF} \times \text{DF}
\]

where MCC is the unpaid net capacity charges under FCM PI. ISO will estimate the pre-settlement amount at the beginning of the month, and then adjust the holding to the final settlement amount when the monthly settlement is ready, finally MCC will become to zero once the monthly invoice is fully paid off. During high risk months (summer and winter), SF is calculated as the square root of the number of summer or winter months remaining in the seasonal period. For example, the SF will be two (square root of four) in June, and will become one (square root of one) in September. During all the shoulder months, the scaling factor will be one. Historical data suggests that the probability of scarcity event in shoulder months is not strictly zero. The combination of MAX function and 0.1 effectively sets current month FA floor to be 10% of monthly stop loss. Ten percent of the potential exposure is a rough estimate of the impact of such events.

**Examples**

Case 1: Consider a simple one resource portfolio and assume the following key inputs:

\[
\text{DFAMW} = 100 \text{ MW}
\]

\[
\text{CWAP} = 0 \text{ (i.e., the largest and only resource is not available during the scarcity event hours)}
\]

\[
\text{ABR} = 0.90 \text{ for the month}^8
\]

\[
\text{Forward Capacity Auction Starting Price} = \$15,000 /\text{MW-month}
\]

\[
\text{Capacity price for the resource} = \$2,744 /\text{MW-month}
\]

---

\(^5\) The potential exposure is a monthly value calculated for the Designated FCM Participant’s portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average Capacity Clearing Price for the portfolio.

\(^6\) The purpose of the scaling factor is to address the liquidation risk. We assume that the probability of scarcity event occurrence in each month is independent of each other. Under the central limit theorem, the distribution of the sum of independent and identical random variables can be approximated with a normal distribution. Although the number of months is not large enough to satisfy the central limit theorem, we assume, as a proxy, that the total risky obligations in the remaining months of a season are normally distributed so the exposure to loss declines with the square-root of the number of months remaining in the season.

\(^7\) The discount factor is based on the likelihood of single resource portfolio to reach its monthly stop-loss under different capacity performance payment rates. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF equals 0.75; and thereafter, DF equals 1.00.

\(^8\) System wide average balancing ratio for summer months is close to 0.90 during 2010 to 2013 period.
Potential Exposure (PE) = $15000 - 2744 = $12,256/MW

Assuming that there is no capacity charge (net penalty) in the previous month,

MCC = 0

The resource has not reached its annual stop loss limit,

SLF = 0

DF = 0.75

It is the July delivery month (3 months left in summer commitment period).

SF = 1.732

The FA requirement for the month would be the exposure to net penalties, which by formula [3] above equals:

\[
FA = MCC + DFAMW \times PE \times (\text{MAX}(ABR - CWAP, 0.1)) \times SF \times DF
\]

\[
FA = 0 + 100 \times 12256 \times (\text{MAX}(0.90 - 0.0, 0.1)) \times 1.732 \times 0.75
\]

\[
FA = 100 \times 12256 \times 0.9 \times 1.732 \times 0.75
\]

\[
FA = $1,432,891
\]

Case 2: Consider the previous case with the following change: add an identically sized resource to the portfolio. Assume the capacity price for the second resource is $6661/MW-month.

For this portfolio, we assume that the largest and historically best performing resource is unavailable. Allowing that the resources are independent in availability, that availability follows a binomial distribution, and that the historical average performance of resource two is 90%, the capacity weighted average performance is calculated by formula [2] as:

\[
CWAP = (0.9 \times 100)/200 = 0.45.
\]

\[
PE = 15000 - (100 \times 2744 + 100 \times 6661)/(100 + 100) = 10298
\]

In the case of two 100 MW resources, then, the FA requirement would be:

\[
FA = MCC + DFAMW \times PE \times (\text{MAX}(ABR - CWAP, 0.1)) \times SF \times DF
\]
FA = 0 + 200 x 10298 x (MAX(0.90-0.45, 0.1)) x 1.732 x 0.75
FA = 200 x 10298 x 0.45 x 1.732 x 0.75
FA = $1,203,974

Case 3: Consider the previous case with the following change: adding one 500 MW resource into the portfolio. Assume a capacity price for the 500MW resource is $14999/MW-month.

For this portfolio, given that the 500 MW resource is unavailable, the exposure to penalties is mitigated when both 100 MW resources are available. Assume both 100 MW resources have historical average performance of 90%. The capacity weighted average performance is calculated:

CWAP = (100*0.9+100*0.9)/700 =0.257
PE = 15000- (100 x 2744 +100 x 6661+500 x 14999)/(100+100+500) = 2943

In the case of a portfolio consisting of one 500 MW resource and two 100 MW resources, then the FA requirement would be:

FA =MCC + DFAMW x PE x (MAX(ABR – CWAP, 0.1)) x SF x DF
FA = 0 + 700 x 2943 x (MAX(0.90-0.257, 0.1)) x 1.732 x 0.75
FA = 700 x 2943 x 0.643 x 1.732 x 0.75
FA = $1,720,763

Case 4: Consider a case with the same portfolio as in case 3 but in January (2 months left in winter commitment period) with ABR =0.7

In this case the FA requirement would be:

FA = MCC + DFAMW x PE x (MAX(ABR – CWAP, 0.1)) x SF x DF
FA = 0 + 700 x 2943 x (MAX(0.7-0.257, 0.1)) x 1.414 x 0.75
FA = 700 x 2943 x 0.5 x 1.414 x0.75

10 The system wide ABR for winter months is approximately 0.7 during the 2010 to 2013 period.
Case 5: Now consider a case in which the FA floor has been triggered. Consider a 100 MW system-backed import resource in October with system wide ABR = 0.6. The resource has a capacity price of $2744 /MW-month.

\[ PE = 15000 - 2744 = \$12256 /MW-month \]

The FA requirement for the month would equal:

\[ FA = MCC + DFAMW \times PE \times (\text{MAX}(ABR - CWAP, 0.1)) \times SF \times DF \]

\[ FA = 0 + 100 \times 12256 \times (\text{MAX}(0.6 - 1.0, 0.1)) \times 1 \times 0.75 \]

\[ FA = 100 \times 12256 \times 0.1 \times 1 \times 0.75 \]

\[ FA = \$91,920 \]

Case 6: Now consider Case 3 in which the largest resource has reached its annual stop loss limit in December. The portfolio has a net penalty resulting in a charge for the previous month MCC = $1,000,000.

\[ CWAP = (0.9 \times 100)/200 = 0.45. \]

\[ PE = 15000 - (100 \times 2744 + 100 \times 6661)/(100+100) = 10298 \]

\[ ABR = 0.7 \]

The FA requirement for the month would equal:

\[ FA = MCC + DFAMW \times PE \times (\text{MAX}(ABR - CWAP, 0.1)) \times SF \times DF \]

\[ FA = 1000000 + 200 \times 10298 \times (\text{MAX}(0.7 - 0.45, 0.1)) \times 1.732 \times 0.75 \]

\[ FA = 1000000 + 200 \times 10298 \times 0.25 \times 1.732 \times 0.75 \]

\[ FA = \$1,668,875^{11} \]

\[ ^{11}\text{Once the market participant pays off the last month capacity charge of 1,000,000, the FA will drop to $668,875.} \]
Case 7: Now consider Case 2 in which the second resource is a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to FCA 9. According to Market Rule III.13.7.3.1, the potential exposure of the second resource is zero. The Forward Capacity Auction starting price used to calculate potential exposure for the second resource shall equal to the capacity clearing price of the same resource.

$$CWAP = \frac{(0.9\times 100)}{200} = 0.45.$$  

$$PE = \frac{(100 \times 15000 + 100 \times 6661)/(100+100) - (100 \times 2744 + 100 \times 6661)/(100+100)}{100} = 6128$$

The FA requirement would be:

$$FA = CC + DFAMW \times PE \times (\text{MAX}(ABR - CWAP, 0.1)) \times SF \times DF$$

$$FA = 0 \times 200 \times 6128 \times (\text{MAX}(0.90-0.45, 0.1)) \times 1.732 \times 0.75$$

$$FA = 200 \times 6128 \times 0.45 \times 1.732 \times 0.75$$

$$FA = $716,445.$$
To: Budget and Finance Subcommittee  
From: Marc Montalvo, Director Enterprise Risk Management  
Date: November 25, 2013  
Subject: Summary of Changes to Proposed FAP Language  

At the November 18, 2013 Budget and Finance subcommittee meeting, several comments were made and questions were raised regarding the intent and mechanics of the proposed Financial Assurance Policy (FAP) provisions. A revised version of the proposed FAP provisions has been posted for review at the November 25, 2013 Budget and Finance subcommittee meeting. To aid those discussions, summarized below are the questions and a description of the changes to the proposed FAP language that address them.

1. With respect to the formulation, it was suggested that the language would be clearer if the variables in the formula, which appear to be acronyms, were spelled out. To that end, I have clarified the variables by assigning names and acronyms that more straightforwardly align with the meaning of the variable. For example, MCC is now written out as monthly capacity charge.

2. During the discussion of the variable called CSOFA, it became apparent that the chosen variable name was a source of confusion. CSOFA is a MW amount not a dollar amount. To reduce confusion, CSOFA is replaced with DFAMW or delivery financial assurance MW.

3. There were several questions regarding the timing of the calculation and inclusion of the MCC component in the FCM Delivery Financial Assurance amount. Language has been added to the MCC provision that clarifies when and how the MCC value will be calculated.

4. There were several questions regarding what capacity prices would be used in the calculation of PE (potential exposure). Language has been added to the PE provisions that clarifies that the capacity price will be that used to compute the Capacity Base Payment for a given CSO. Additional language has been added to address the computation of PE in the case of a resource that cleared prior to FCA9 and elected a multi-year price.

5. There were questions regarding how actual data would be included into the three year calculation of actual and what weighting actual would receive. Language has been added to both the ABM (average balancing ratio) provisions that clarify that the actuals are scarcity condition duration weighted. Also, for both the ABM and CWAP (capacity weighted average performance, formerly VWAP) actuals replace the temporary values as the applicable group of months is completed.
6. A question was asked about the case where there are no scarcity conditions. No language changes were made to address this case. Average performance is defined in terms of performance during scarcity conditions, thus, unless and until there are such conditions, there are no actuals and the temporary values will be used.

7. A question was asked about the categories of resources with temporary CWAP values and whether they were fine enough on the one hand or too explicit on the other. Upon review, language has been added to distinguish CC and CT resources from steam resources. The list of imports, DR and renewable resources has been replaced with a simple reference to “other” resources.
TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot, Pat Gerity and Sebastian Lombardi, NEPOOL Counsel

DATE: November 27, 2013

RE: ISO-NE “Exigent Circumstances” Filing: FCM Administrative Pricing Rule Changes

You will be asked at the December 6, 2013 annual meeting to consider whether to take any action in response to ISO-NE’s “Exigent Circumstances” filing that was submitted to the FERC on November 25, 2013 (FERC Docket No. ER14-463). In that filing, ISO-NE proposes: (i) a proposal to address what it identifies as a “gap” in the Insufficient Competition rules; (ii) an administrative rate of $7.025/kW-month to be applied if there is Insufficient Competition (as ISO proposes to redefine it) or Inadequate Supply in the eighth Forward Capacity Auction (“FCA8”); and (iii) additional clarifying changes to the administrative pricing rules in the FCM (collectively, the “FCM Pricing Rule Changes”). A copy of the ISO-NE filing is included with this memorandum.

The ISO had identified its proposed changes for limited discussion at the Markets Committee, but did not identify them soon enough for a vote at either the Markets Committee or the Participants Committee. Instead, ISO-NE elected to file the FCM Pricing Rule Changes unilaterally, citing its authority in Section 11.2 of the Participants Agreement to file changes in Exigent Circumstances before full consultation with NEPOOL through the FERC-approved Participant Processes. “Exigent Circumstances” are defined in the Section 1 of the Participants Agreement to be circumstances where:

ISO determines in good faith that (i) failure to immediately implement a new Market Rule, Operating Procedure, Reliability Standard, provision of the Information Policy, Non-TO OATT Provision or Manual would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the New England Markets, and (ii) invoking the procedures set forth in Section 11.1, 11.3 or 11.4 would not allow for timely redress of ISO’s concerns.

The ISO-NE filing explains that it has made this determination in good faith based on material and unexpected changes in circumstances that have caused it to conclude it must have its desired changes in effect for FCA8. ISO’s explanation: “If the flaws go unaddressed, the auction could produce anomalous results.” For that reason, the ISO takes the position that the FERC can only consider whether its proposal is just and reasonable and it must accept its proposal unless it finds that ISO’s proposed changes are not just and reasonable.

There is no need for Participants Committee action on this matter, although we have included information to permit action if the Committee so desires. Based on feedback provided to date, it appears that there is broad agreement of the members that the FERC should act in time to apply any determinations to FCA8. The Committee certainly could, if members conclude...
they have enough information, discussion and process, vote on a motion to support the ISO’s proposed changes, or alternatively on a different proposal than that presented by the ISO’s filing. NEPOOL counsel will be working with the Officers on NEPOOL’s submission to the FERC in response to the ISO’s filing, and the Officers and NEPOOL counsel welcome member input. Many of you have raised concerns about the process ISO-NE has followed here, and in particular whether the conditions justify an Exigent Circumstances filing. The Committee may go into Executive Session for discussion. If the Committee decides it is prepared for and wishes to take formal action at the meeting, the following form of resolution, which can be adjusted as needed, could be used:

RESOLVED, in response to proposed revisions to Market Rule 1 to address concerns with the current FCM administrative pricing rules (the FCM Pricing Rule Changes) as filed by ISO-NE on November 25, 2013 in FERC Docket No. ER14-463, that the Participants Committee hereby:

[specify]

[E.g., supports the FCM Pricing Rule Changes, 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 Markets Committee.]
November 25, 2013

VIA ETARIFF FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ISO New England Inc., Docket No. ER14-___-000;
    Exigent Circumstances Filing of Revisions to Forward Capacity Market
    Rules

Dear Secretary Bose:

    Pursuant to Section 205 of the Federal Power Act (“FPA”),\(^1\) ISO New England Inc. (“ISO-NE” or the “ISO”) hereby electronically submits this transmittal letter and related materials regarding revisions to certain rules governing the Forward Capacity Market (“FCM”).\(^2\)

    The ISO proposes that these revisions (the “Rule Revisions”) become effective on January 24, 2014. The ISO is submitting the Rule Revisions as an “Exigent Circumstances” filing under Section 11.2 of the Participants Agreement, for the reasons set forth in Section IV below.

I. INTRODUCTION AND SUMMARY

    When the FCM Settlement Agreement was negotiated,\(^3\) there were significant concerns about pricing where sufficient competition was lacking or where seller market power could inappropriately raise prices. Three provisions were included in the

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\(^2\) The FCM rules are included in Market Rule 1, which is Section III of the ISO New England Inc. Transmission, Markets and Services Tariff (the “ISO-NE Tariff”). Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO-NE Tariff.
\(^3\) The FCM Settlement Agreement was approved in *Devon Power LLC*, 115 FERC ¶ 61,340 (2006), *order on reh’g*, 117 FERC ¶ 61,133 (2006). The initial rules implementing the FCM Settlement Agreement were accepted conditionally in *ISO New England Inc.*, 119 FERC ¶ 61,045 (2007), *order on reh’g*, 120 FERC ¶ 61,087 (2007).
agreement to address these concerns. The first provision, which became the Inadequate Supply rule (the “IS Rule”),\(^4\) was intended to address the situation where the total of existing and all new resources was less than the Installed Capacity Requirement (“ICR”). The second provision, which became the Insufficient Competition rule (the “IC Rule”),\(^5\) was intended to address the situation where there were less existing resources than ICR and not enough eligible new resources to assure competition in the auction (although when combined, the eligible existing and new resources exceeded ICR). The third provision became the Capacity Carry Forward Rule (the “Carry Forward Rule”),\(^6\) and was intended to address the situation where a large resource met a zonal need, but eliminated any need for new resources in the subsequent auction. Each of these rules was supported by stakeholders and accepted by the Federal Energy Regulatory Commission (“FERC” or “Commission”).\(^7\) Each of these three rules, when triggered, specify administrative prices that will apply in place of prices derived from the Forward Capacity Auction (“FCA”). In general and in simplest terms, these rules sought to tie those administrative prices to the Cost of New Entry (“CONE”).

In its April 13, 2011 paper hearing order,\(^8\) the Commission concluded that under the offer floor mitigation structure, the determination of CONE was moot and required its replacement in the administrative pricing rules. In this regard, the Commission stated: “[w]e reject NEPGA’s suggestion that the price paid to existing resources in the event of inadequate supply or insufficient competition should be slightly above the benchmark cost of a peaker. In the context of the revised mitigation regimes proposed by ISO-NE and accepted by the Commission, we find this suggested modification unnecessary.”\(^9\) In its December 3, 2012 filing, the ISO complied with the Paper Hearing Order and eliminated the use of CONE in the administrative pricing rules. In the Carry Forward Rule, CONE was replaced with the Offer Review Trigger Price of a combustion turbine. In the IS Rule and IC Rule, the ISO believed that CONE should also be replaced with the Offer Review Trigger Price of a combustion turbine, but such a change was beyond the scope of compliance, and so for the IS Rule and the IC Rule, CONE was replaced with the clearing price from the last competitive auction. However, in this regard the ISO stated that: “…the ISO believes that the Inadequate Supply and Insufficient Competition pricing provisions for existing resources should instead refer to 1.1 times the Offer Review Trigger Price for a combustion turbine. The ISO intends to initiate a stakeholder

\(^4\) Market Rule 1 § III.13.2.8.1.
\(^5\) Market Rule 1 § III.13.2.8.2.
\(^6\) Market Rule 1 § III.13.2.7.9.
\(^9\) Id. at P 342.
process to make this change in the near future, preferably in time to be effective for the eighth FCA.”

For three reasons, the ISO did not undertake that stakeholder process in a timely manner: (1) because of the pressures of other important projects (Hourly Reoffers, Day-Ahead Market timing, FCM Pay for Performance, the Winter 2013/14 program, Reserve Market enhancements and Regulation market changes), (2) because of the general perception that the region would be long on resources and that the triggering in the eighth FCA (“FCA 8”) of the IS Rule or the IC Rule would therefore be unlikely, and (3) because the ISO anticipated developing a sloped demand curve that would allow the elimination of these administrative pricing mechanisms.

The ISO has conducted seven capacity auctions since 2008. In each of these auctions, with one limited exception,\(^{11}\) the market cleared at the price floor and the region has procured significant excess capacity. And as recently as the early fall of 2013, it appeared very likely that a surplus of capacity resources (new and existing) would be participating in FCA 8.

Well after the deadlines for qualifying new resources to participate in FCA 8, however, the New England capacity supply situation changed dramatically. In August, after prevailing in its litigation with the State of Vermont, Entergy announced the retirement of the 604 MW Vermont Yankee nuclear plant and submitted a non-price retirement request (“NPRR”).\(^{12}\) In October, an additional 2,500 MWs left the FCM by submitting NPRRs. These events changed the supply-demand balance from a surplus of existing resources of over 2,000 MWs to a deficiency of existing resources of over 1,000 MWs, compared with the ICR. The abrupt change in the supply-demand balance, coupled with the general decline in the amount of new resources seeking to participate in the auction (likely because of low prices set by the current vertical demand curve structure, which signaled that new resources were not needed), means that it is possible that the IC Rule will be invoked in FCA 8. Given that possibility, in hindsight the ISO should have undertaken the stakeholder process discussed in the December 2012 Compliance Filing. In addition, and as fully explained in the answer to the complaint filed on October 31, 2013 by the New England Power Generators Association (“NEPGA”) in Docket No. EL14-7-000 (the “NEPGA Complaint”), the ISO did not support the proposed modifications to the Carry Forward Rule and, therefore, did not support Exelon’s proposal to change that rule.


\(^{11}\) In FCA 7, the NEMA/Boston Capacity Zone began the auction needing new capacity. Footprint Power cleared the auction at a price of $14.99/kW-month and, because there was Insufficient Competition in that zone, all existing resources received Capacity Supply Obligations and will be paid $6.66/kW/month.

\(^{12}\) NPRRs are addressed in Section III.13.2.5.2.5 of the ISO-NE Tariff.
In light of these circumstances, the ISO undertook analyses of the potential application of the IS Rule and the IC Rule. In addition to the pricing issue discussed above, this analysis exposed a logical flaw in the triggering of the IC Rule (hereinafter referred to as the “IC Gap”). Recognizing this flaw and that the existing administrative pricing formula contained in the rules could result in unjust and unreasonable prices in FCA 8, the ISO submits the following two rule changes.

First, the Rule Revisions address the range of circumstances in which the Insufficient Competition rule is triggered, to remedy the IC Gap. See Section V.A of this transmittal letter.

Second, the Rule Revisions modify the administrative pricing established by the IS and IC Rules, when those rules are triggered. This topic is the subject of the NEPGA Complaint. See Section V.B of this transmittal letter. In short and for the reasons explained below, the ISO is proposing a rate of $7.025/kW-month to be applied in FCA 8. The ISO, beginning in the New England Power Pool (“NEPOOL”) stakeholder process in January, will propose a downward sloping demand curve that will solve significant flaws in the FCM and should alleviate the need for these administrative pricing rules; the ISO plans to file a demand curve with the Commission in the summer of 2014.

The Rule Revisions are narrowly targeted to address these two crucial issues in advance of the conduct of FCA 8, which will start on February 3, 2014. In discussing those two issues with stakeholders, stakeholders raised several other rule provisions that warrant clarification, and so this filing also proposes three additional rule clarifications. First, the Rule Revisions address subsection III.13.2.8.1.1 of the IS Rule, to remove the definition of “New Capacity Required” for the Rest-of-Pool Capacity Zone and replace it with a definition of “New Capacity Required” for the system-wide context. See Section V.C of this transmittal letter. Second, the Rule Revisions modify Section III.13.2.8.2(a) of the IC Rule to clarify the treatment of permanently de-listed resources (and capacity otherwise obligated) in the calculation of any amount by which the Installed Capacity Requirement (“ICR”) or Local Sourcing Requirement (“LSR”), as applicable, exceeds capacity offered from existing capacity resources. See Section V.D of this transmittal letter. Finally, the Rule Revisions clarify the treatment of de-list and export bids when the Capacity Clearing Price is set administratively due to the operation of the Carry Forward Rule. See Section V.E of this transmittal letter.

II. DESCRIPTION OF ISO-NE; COMMUNICATIONS

ISO-NE is the private, non-profit entity that serves as the regional transmission organization (“RTO”) for New England. ISO-NE operates the New England bulk power

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13 See ISO-NE Tariff § III.13.2.8.2.

14 See ISO-NE Tariff § III.13.2.7.9.
system and administers New England’s organized wholesale electricity market pursuant to the ISO-NE Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, ISO-NE has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council (“NPCC”) and the North American Electric Reliability Corporation (“NERC”).

Correspondence and communications in this proceeding should be addressed to:

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III. STANDARD OF REVIEW

This filing is made pursuant to Section 205 of the FPA, which “gives a utility the right to file rates and terms for services rendered with its assets.”\(^\text{15}\) Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”\(^\text{16}\) whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”\(^\text{17}\) The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”\(^\text{18}\) The Tariff modifications herein “need not be the only reasonable methodology, or even the most accurate.”\(^\text{19}\) As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept ISO-NE’s Section 205 filing if it is just and reasonable.\(^\text{20}\)

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\(^{15}\) Atlantic City Elec. Co. v. FERC, 295 F.3d 1, 9 (D.C. Cir. 2002).

\(^{16}\) Id. at 10 (quoting City of Winnfield v. FERC, 744 F.2d 871, 876 (D.C. Cir. 1984)).

\(^{17}\) Id. at 9.


\(^{19}\) Oxy USA, Inc. v. FERC, 64 F.3d 679, 692 (D.C. Cir. 1995).

\(^{20}\) Cf. Southern California Edison Co., et al., 73 FERC ¶ 61,219 at p. 61,608 n.73 (1995) (“Having found the plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (citing Cities of Bethany, 727 F.2d at 1136)).
IV. DESCRIPTION OF EXIGENT CIRCUMSTANCES

As already noted, the ISO is submitting the Rule Revisions as an “Exigent Circumstances” filing under Section 11.2 of the Participants Agreement. Section 11.2 states:

Exigent Circumstances. In Exigent Circumstances, ISO may unilaterally, upon written notice to the Participants Committee and Individual Participants, file with the Commission pursuant to Section 205, if necessary, and implement a new or amended Market Rule, Operating Procedure, Manual, Reliability Standard, provision of the Information Policy (subject to 11.3), General Tariff Provision, or Non-TO OATT Provision.

“Exigent Circumstances” are defined in the Participants Agreement as circumstances such that the ISO determines in good faith that failure to immediately implement a change would substantially and adversely affect either system reliability or security or the competitiveness or efficiency of the New England Markets, and that invoking the normal stakeholder review procedures set forth in Section 11.1, 11.3 or 11.4 of the Participants Agreement would not allow for timely redress of the ISO’s concerns.

Exigent Circumstances are presented here, and the ISO has made the good faith determinations required in Section 11.2 of the Participants Agreement. Prompt implementation of the Rule Revisions is necessary to address the flaws in FCM rules prior to the conduct of FCA 8 during the first week of February 2014. If the flaws go unaddressed, the auction could produce anomalous results.

Unfortunately, the full NEPOOL stakeholder process, which would provide the benefit of more deliberative discussions between the ISO and stakeholders while allowing the Commission sufficient time to issue an order, cannot be accomplished in time for the Rule Revisions to be in place prior to the conduct of FCA 8. Consistent with the nature of an Exigent Circumstances filing, the ISO has drafted the Rule Revisions to make small but important changes that require expedited acceptance; this expedited schedule is necessary in order to assure that just and reasonable rules are in place to conduct FCA 8. To accomplish this goal, a Commission order is needed no later than January 24, 2014, when the necessary auction input files and software must be finalized for the auction. To allow the Commission 60 days within which to rule upon this filing, the rules needed to be submitted no later than November 25. This schedule simply did not allow sufficient time for the ISO to draft rules, present them to the NEPOOL Markets Committee with appropriate notice, time for discussion and a vote, and then provide notice and a voting opportunity at the Participants Committee. The ISO is pursuing a narrow set of changes because there is a very limited window of time to implement changes for FCA 8, which will start on February 3, 2014. While broader design changes might accomplish similar or additional objectives, the short implementation timeframe precluded consideration of such changes.
Although the full Participant Processes cannot be conducted under these pressing circumstances, the ISO discussed the substance of the Rule Revisions over two meetings of the NEPOOL Markets Committee, on November 13 and 18, 2013. Because of the timing, NEPOOL elected not to have a Participants Committee discussion on the matter.

The ISO has provided written notice of this filing to the Secretary of the NEPOOL Participants Committee, as required by Sections 11.2 and 17.11(e) of the Participants Agreement.

V. DESCRIPTION OF, AND JUSTIFICATION FOR, THE RULE REVISIONS

A. Revisions Addressing the IC Gap

The IC Gap identified by the ISO exists when there are more than 300 MW of new generation and new demand resources (new import resources are excluded from this calculation), but less than the amount of New Capacity Required, defined as the shortfall in existing capacity (i.e., the difference between ICR and existing capacity). Insufficient competition is not triggered when the sum of New Generation and New Demand Response falls into the gap between 300 MW and the amount of New Capacity Required. However, Insufficient Competition would be triggered if the sum of new generation and new demand is higher than the amount of New Capacity Required. To trigger Insufficient Competition below 300 MW and above New Capacity Required, but not in between, is counter-intuitive and cannot be supported from a market design perspective.

1. Hypothetical Example

To explain the IC Gap, assume the hypothetical megawatt values for an FCA shown in two different cases in the table below.

<table>
<thead>
<tr>
<th>Case 1 (MW)</th>
<th>Case 2 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Existing Capacity Resources</td>
<td>9,500</td>
</tr>
<tr>
<td>2 ICR</td>
<td>10,000</td>
</tr>
<tr>
<td>3 Shortfall in Existing Capacity Resources (i.e., New Capacity Required) (1-2)</td>
<td>-500</td>
</tr>
<tr>
<td>4 New generation</td>
<td>200</td>
</tr>
<tr>
<td>5 New demand response</td>
<td>200</td>
</tr>
<tr>
<td>6 New imports</td>
<td>500</td>
</tr>
</tbody>
</table>
The Honorable Kimberly D. Bose, Secretary  
November 25, 2013  
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7 Total new resources (4+5+6)  

8 Total eligible resources for FCA (1+7)  

9 Surplus entering FCA (8-2)  

2. How the Hypothetical Example Illustrates the IC Gap

The provisions of the IC Rule (Section III.13.2.8.2 of Market Rule 1) are provided below with commentary in italicized brackets using numbers from Cases 1 and 2 in the table above, illustrating the IC Gap (which is contained in the existing language of subsections (b)(i) and (ii)):

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement; [This is true in both Cases 1 and 2, as evidenced by the 500 MW shortfall in Line 3] and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources [this provision is not triggered in either Case 1 or Case 2, because there is 400MW currently remaining];

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; [In Case 1 this provision is not triggered because 400MW is offered, which is not more than the 500MW of new capacity required] [In Case 2 this provision is triggered because the 600 MW offered by new generation and new demand resources is more than the New Capacity Required (500 MW) but less than twice the amount of New Capacity Required (1000 MW)] or

(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New
Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable [this provision is not triggered in this hypothetical].

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources … shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. …

Accordingly, using the numbers from Case 1, Insufficient Competition pricing would not be triggered because more than 300 MW of new capacity are offered, but none of the circumstances described in subsection (b) are present. However, using the numbers from Case 2 (increasing the 400 MW of New Generation and New Demand Resources to 600 MW), Insufficient Competition pricing would be triggered because the 600 MW is between the 500 MW shortfall and twice that shortfall — i.e., the circumstances described in provision (b)(2) are present. In short, the IC Gap means that (using these examples) Insufficient Competition pricing would not be triggered if the auction is 300 to 500 MW long, but is triggered if the auction is 500 to 1000 MW long. So adding more new resources to the FCA would cause the auction to be deemed less competitive; that is clearly a gap in the rule language, not a logical or intended outcome.

3. The IC Gap Can Produce Anomalous Outcomes

The consequences of the IC Gap are not logical or consistent with the overall intent of the IC Rule. Again, examples best illustrate this point. Continuing with the hypothetical numbers above, there are two outcomes under the two illustrative cases. First, assume that, of the 400 MW of excess resources in Case 1, 300 MW drop out of the auction at the starting price and the next 150 MW seek to drop out at $12/kW-month. Since allowing the 150 MW to leave the FCA would drop the system below ICR, the auction would stop at a price of $12/kW-month. Case 1 demonstrates the IC Gap where Insufficient Competition is not triggered, and so all resources would receive $12/kW-month. Using Case 2, and the same auction prices, the auction would still stop at $12/kW-month. However, since Insufficient Competition is triggered, new resources will receive the $12/kW-month price, but Existing Resources will receive the administrative price associated with the Insufficient Competition rule.

The IC Gap is truly a gap in the rule; it is not justified by any economic principles and undermines the effectiveness of the insufficient competition provisions. Therefore, the ISO believes it must be remedied.
4. **Proposed Revision to Remedy the IC Gap**

To eliminate the IC Gap, the ISO proposes revising subsection (b)(ii) of the rule to delete the “lower limit” of the trigger (with the strikethrough showing that deletion):

the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; …

With this revision, subsection (b) of the IC Rule would be triggered either when the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is less than 300 MW, or where the amount of new capacity offered is less than twice the amount of New Capacity Required. This will produce a correct and consistent economic result.

**B. Revisions Addressing Administrative Pricing in the Insufficient Competition and Inadequate Supply Rules**

1. **Background and History of FCM Administrative Pricing**

   The IC Rule is applied system-wide or in an import-constrained Capacity Zone when there is enough new entry from generation and demand resources in an FCA, when combined with the total existing resources (generation, demand response and imports), to meet the ICR for that year, but there is not sufficient new entry of generation and demand response resources to assure that the auction result is competitive. In this situation, the FCA is administered as usual, but only new resources receive the Capacity Clearing Price. Existing capacity resources are paid the lower of the Capacity Clearing Price, or an administrative price currently specified in the rules as 1.1 times the Capacity Clearing Price in the last competitive FCA, which would be $3.46/kW-month.

   Administrative pricing is also reflected in the IS Rule. An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In that case, new resources are paid the Forward Capacity Auction Starting Price and existing resources are paid 1.1 times the Capacity Clearing Price for the most recent FCA not having Inadequate Supply. That administrative price is also paid in conditions of system-wide Inadequate Supply, which occurs if, at the Forward Capacity Auction Starting Price, the total amount of capacity offered in the FCA is less than the ICR.

   For the first seven FCAs, the administrative price specified in the IS/IC Rules was 1.1 times CONE. When the FCM rules were initially filed in 2007, they specified that CONE was $7.50/kW-month for the first FCA, and so 1.1 times CONE equaled $8.25/kW-month at that time. Pursuant to provisions in the initial rules, the CONE calculated for the next two FCAs decreased to $6.00/kW-month and then to $4.918/kW-
month, respectively. The rules were then revised in February 2010 to state that for FCA 4, CONE again would be $4.918/kW-month.\textsuperscript{21} The revised rules also contained a modified formula to calculate CONE for subsequent FCAs, but that formula was never triggered, because the revised rules also stated that if the FCA cleared at the floor price then in place, the $4.918/kW-month CONE value would simply be indexed based on a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. The floor price provision has applied in all FCAs since FCA 4, and as a result of the required indexing, CONE has increased from $4.918/kW-month in FCA 4 to $6.055/kW-month in FCA 7. Using that CONE value, the administrative price of 1.1 times CONE equaled $6.66/kW-month in FCA 7. This administrative price was applied in the NEMA/Boston Capacity Zone due to Insufficient Competition in that zone in FCA 7.

Subsequently, the Commission ordered the ISO to eliminate the FCA floor price and the use of CONE. And, as noted above, in the 2011 Paper Hearing Order the Commission rejected “NEPGA’s suggestion that the price paid to existing resources in the event of insufficient competition should be slightly above the benchmark cost of a peaker.”\textsuperscript{22} In its compliance filing, accordingly, the ISO replaced the 1.1 times CONE element with an element specifying 1.1 times the clearing price in the most recent competitive FCA.\textsuperscript{23} This provision yields an administrative price of $3.46/kW-month for FCA 8. In that compliance filing, the ISO noted, however:

Now that the Offer Review Trigger Price mechanism has been developed and is poised to be implemented, however, the ISO believes that the new Offer Review Trigger Price for a combustion turbine would be a far better estimate of the revenues that a new peaking resource would need to recover from the capacity market. Hence, while the instant filing replaces CONE with the Capacity Clearing Price from the most recent competitive FCA, as directed by the Commission, the ISO believes that the Inadequate Supply and Insufficient Competition pricing provisions for existing resources should instead refer to 1.1 times the Offer Review Trigger Price for a combustion turbine. The ISO intends to initiate a stakeholder process to make this change in the near future, preferably in time to be effective for the eighth FCA.\textsuperscript{24}

A price of 1.1 times the current Offer Review Trigger Price for a combustion turbine for FCA 8 would equate to $11.00/kW-month.


\textsuperscript{22} See Paper Hearing Order at P 342.

\textsuperscript{23} See December 2012 Compliance Filing at 44.

\textsuperscript{24} Id.
Because of the expectation that neither the IS Rule nor the IC Rule would be triggered in FCA 8, the anticipation that the administrative pricing rules would be supplanted with a sloped demand curve, and because of workload resulting from other high priorities in the market design area, including Hourly Reoffers, Day-Ahead Market timing, FCM Pay for Performance, the Winter 2013/14 program, Reserve Market enhancements and Regulation market changes, the ISO did not pursue this change.

2. Changing Circumstances for FCA 8

As noted in Section I of this transmittal letter, in the summer and early fall of 2013, it appeared that a surplus of capacity resources (new and existing) would be participating in FCA 8. Over 3,000 MW of new resources had been qualified to participate in FCA8 and there was an excess of roughly 2,000 MW of existing resources. In October 2013, however, the outlook for FCA 8 changed dramatically. Over 3,000 MWs left the FCM by submitting NPRRs. This changed the supply-demand balance from a surplus of existing resources of over 2000 MWs to a deficiency of existing resources of over 1000 MWs, compared with the ICR. In addition, roughly 800 MW of qualified new resources elected not to participate in the auction. The abrupt change in the supply-demand balance, coupled with the decline in the amount of new entry, means that it is possible that the IC Rule will be invoked. In light of these circumstances, the ISO believes that the administrative rate must be addressed now.

3. Rationale for Proposed Administrative Price

As noted earlier, the proposed rule changes replace “1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction” with a value of $7.025/kW-month. This value is derived by essentially applying the rules in place for FCA 7. Specifically, if CONE were still applicable for FCA 8, it would be $6.386 (i.e., the FCA 7 CONE of $6.055 escalated using the Handy-Whitman Index of 1.0546). Multiplying that $6.386 figure by 1.1 yields $7.025/kW-month. While the ISO recognizes that this rule is no longer in effect, the ISO believes it is the most appropriate rate under the current and rapidly changing circumstances in New England. There are several reasons why the ISO believes that this rate is appropriate for FCA8.

While the ISO continues to recognize that a downward-sloping demand curve centered around a well-supported CONE is the best longer-term solution, the ISO simply cannot develop such a curve and have it in place for FCA8. Even if the ISO could, it has not developed the appropriate CONE value and vetted it through the stakeholder process. In this regard, it is noteworthy that the updated Offer Review Trigger Prices currently being developed by the Internal Market Monitor and reviewed by stakeholders appear materially different than the current Offer Review Trigger Price rates contained in the ISO-NE Tariff. For example, the cost of a combined-cycle unit now appears lower than a combustion turbine, and its cost is lower than historical values; this indicates that CONE will certainly be different than the existing values and may be lower when updated for current market conditions.
As noted earlier, the resource supply circumstances in New England did not change until well after new resources could qualify to participate in FCA 8. The current process, wherein NPRRs are received late in the process, is deficient. This is because there is no opportunity for new resource entry at this late stage of the process. While there were new resources that did qualify, the amount of new generation and new demand response continued the declining pattern seen over earlier auctions. While this hypothesis cannot be proven, the ISO’s perspective is that low prices were expected to prevail in FCA 8 and, therefore, qualifying new resources made little sense when the price floor was being eliminated and there was a significant excess of supply.

Existing resources have been receiving compensation in the first seven FCAs by virtue of the operation of the floor price. These floor prices have distorted the past auction clearing prices, and it is likely that these prices are higher than those that would have otherwise prevailed. Given this, an increase in the level of the administrative price for existing resources — from the currently effective $3.46 to $11.00 — is not an appropriate administrative outcome.

For these reasons, the ISO believes that the proposed $7.025/kW-month rate addresses these concerns. It recognizes the need to send price signals consistent with evolving market conditions, but also avoids lurching between administrative prices derived from the vertical demand curve, price floors and potentially uncompetitive auctions. The $7.025 rate is derived directly from the tariff language that was in effect for FCA 7 and was used to determine the administrative price in that FCA. This price was recently accepted by resources in the NEMA/Boston Capacity Zone and by the Commission, and the methodology which determined them is familiar to stakeholders. While maintaining the status quo was not an option because it is clearly inconsistent with the changed capacity landscape in New England, neither is moving directly to the ISO’s solution as noted in its December 2012 Compliance Filing because of the reasons cited above.

In sum, the ISO believes that the administrative price under the existing IS/IC rules of $3.46/kW-month is too low, and would undermine investor confidence in the long-term stability of FCM revenues. However, the ISO also believes that the $11.00/kW-month price that would result from applying the formula of 1.1 times the Offer Review Trigger Price for a combustion turbine is too high. Therefore, in order to maintain confidence in the market while balancing the various other factors discussed above, the ISO is proposing to establish $7.025/kW-month as the administrative price, for purposes of FCA 8, calculated using the formula, with escalation of the CONE figure, used for FCA 7. This revision is accomplished through the insertion of the $7.025/kW-month figure in the IS Rule and IC Rule.25

25 See revisions to Sections III.13.2.8.1.1(a) and (d), III.13.2.8.1.2(a), (c) and (d), and III.13.2.8.2(b).
C. **Removal/Replacement of “New Capacity Required” Definition**

The Rule Revisions address Section III.13.2.8.1.1 of the IS Rule, to remove the definition of “New Capacity Required” for the Rest-of-Pool Capacity Zone and replace it with a definition of “New Capacity Required” for the system-wide context.

This removal and replacement is necessary due to a flaw in the market rule. Section III.13.2.8.1.1, entitled “Inadequate Supply in an Import-Constrained Capacity Zone,” contains two definitions of “New Capacity Required”: one for an import-constrained Capacity Zone, and one for the Rest-of-Pool Capacity Zone. However, the Rest-of-Pool Capacity Zone by itself cannot have Inadequate Supply or Insufficient Competition, so the definition of New Capacity Required is unnecessary and confusing.

The replacement of that definition with a definition of “New Capacity Required” system-wide is necessary because that phrase is used in the IC Rule (in subsection (b)(ii)) in determining whether Insufficient Competition exists system-wide, but is not currently defined there. ²⁶ Specifically, the Rule Revisions add the following definition (following the text defining “New Capacity Required” in an import-constrained Capacity Zone):

system-wide, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs) minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated for the Capacity Commitment Period.

D. **Clarification of the Treatment of Permanently De-Listed Resources and Capacity Otherwise Obligated**

The Rule Revisions modify Section III.13.2.8.2(a) of the IC Rule to clarify the treatment of permanently de-listed resources (and capacity otherwise obligated) in the calculation of any amount by which the ICR or LSR, as applicable, exceeds capacity offered from existing capacity resources.

Section III.13.2.8.2(a) states one of the conditions that must be satisfied for Insufficient Competition to exist system-wide or in an import-constrained Capacity Zone, namely, that at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the ICR (net of HQICCs) or the LSR, as applicable. However, as written, that subsection does not make clear (as it should) that permanently de-listed resources and capacity that is otherwise obligated for

²⁶ The existing definition in Section III.13.2.8.1.1 of “New Capacity Required” in the context of an import-constrained Capacity Zone is used in determining (in Section III.13.2.8.2(b)(ii)) whether Insufficient Competition exists in an import-constrained Capacity Zone.
the Capacity Commitment Period should not be considered existing capacity. To clarify that treatment, the Rule Revisions modify subsection (a) – with new language in underscoring – to read:

…the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and…

The new language is consistent with the proposed definition of system-wide New Capacity Required, as discussed in the previous subsection of this transmittal letter.

E. Clarification of the Treatment of De-List and Export Bids When the Capacity Clearing Price Is Set Administratively Due to the Operation of the Carry Forward Rule

The Rule Revisions clarify the treatment of de-list and export bids when the capacity clearing price is set administratively due to the operation of the Carry Forward Rule.

Pursuant to current Section III.13.2.5.2.7, where the Capacity Clearing Price is set pursuant to the IS Rule or IC Rule, and as a result a Permanent De-List Bid, Static De-List Bid or Export Bid clears that would not otherwise have cleared, then the amount of de-listed or exported capacity is not replaced in the current FCA (that is, the amount of capacity procured in the FCA is the ICR (net of HQICCs) or LSR as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and is included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or imported capacity).

The Carry Forward Rule, like the IS and IC Rules, includes an administrative price (see Section III.13.2.7.9.2) to which the Capacity Clearing Price is set if triggered pursuant to Section III.13.2.7.9.1. The current text of Section III.13.2.5.2.7 does not address how de-list and export bids should be treated where the Capacity Clearing Price is set administratively due to the operation of the Carry Forward Rule. Accordingly, to ensure completeness and consistency of treatment of such bids across similar administrative price regimes, the ISO proposes that the text of Section III.13.2.5.2.7 be modified as follows (with the new language underscored):

Where the Capacity Clearing Price is set pursuant to Section III.13.2.7.9 (Capacity Carry Forward Rule), or where payments are set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition)…
VI. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission permit the Rule Revisions to become effective January 24, 2014, without condition, suspension or hearing.

VII. STAKEHOLDER PROCESS

As noted above, the ISO discussed the Rule Revisions in two meetings of the NEPOOL Markets Committee, on November 13 and 18, 2013. Following the November 18, the NEPOOL officers determined to cancel the previously noticed special meeting of the NEPOOL Participants Committee.

VIII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission’s regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Rule Revisions do not modify a traditional “rate” and ISO-NE is not a traditional investor-owned utility. Therefore, to the extent necessary, ISO-NE requests waiver of Section 35.13 of the Commission’s regulations. Notwithstanding its request for waiver, ISO-NE submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission’s regulations:

35.13(b)(2) – ISO-NE respectfully requests that the Commission issue an order accepting the Tariff Revisions to be effective as of January 24, 2014.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on ISO-NE’s website at http://www.committees/directory/default/committee.action?committeeid=1. A copy of this transmittal letter and the accompanying materials have also been sent electronically to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, to the New England Conference of Public Utility Commissioners, and to the Executive Director of the New England States Committee on Electricity. In accordance with Commission rules and practice, there is no need for the Governance Participants or the other entities described above to be included on the Commission’s official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter. Clean and redlined copies of the revised tariff sheets are included with this eTariff filing.

35.13(b)(5) - The reasons for this filing are discussed in this transmittal letter.

35.13(b)(6) – ISO-NE’s approval of the Rule Revisions is evidenced by this filing.
35.13(b)(7) – The ISO has no knowledge of any relevant expenses or costs-of-service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) - The market rule changes herein do not modify a traditional “rate,” and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) - ISO-NE does not provide services under other rate schedules that are similar to the sale for resale and transmission services it provides under the ISO-NE Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions proposed herein.

IX. CONCLUSION

For the reasons stated herein, the ISO respectfully requests that the Commission accept the Rule Revisions without condition, modification or hearing, to be effective on January 24, 2014.

Respectfully submitted,

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Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price
associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.
The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.
(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be \( P_S \) and \( P_E \), respectively. Let the \( m \) prices \((1 \leq m \leq 5)\) submitted by a Project Sponsor for a modeled Capacity Zone be \( p_1, p_2, \ldots, p_m \), where \( P_S > p_1 > p_2 > \ldots > p_m \geq P_E \), and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be \( q_1, q_2, \ldots, q_m \). Then the Project Sponsor’s supply curve, for all prices strictly less than \( P_S \) but greater than or equal to \( P_E \), shall be taken to be:

\[
S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\quad \quad \vdots & \quad \quad \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}
\]

where, in the first round, \( q_0 \) is the resource’s full FCA Qualified Capacity and, in subsequent rounds, \( q_0 \) is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of
that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export
Bids associated with that interface equal to the interface’s transfer limit (minus any accepted
Administrative De-List Bids over that interface) having the highest bid prices shall be included in the
auction as described above; capacity for which Export Bids are not included in the auction as a result of
this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-
Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity
Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List
Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification
Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing
Demand Resource that did not have any such bid accepted in the qualification process, and each existing
Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity
Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included
in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if
permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new
Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity
Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer
Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate
supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below
$1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or
Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List
Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices,
each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater
than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid
shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve
indicating quantities at all of that round’s relevant prices, pursuant to the convention of Section
III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A
dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any
price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a
reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be
included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b).
Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering.** Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity
Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

**III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.**
The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the “Total System Capacity”) shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the
Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a)  **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone’s Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-
Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone.** For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones.** For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone’s Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above
are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).
(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency
Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

**III.13.2.3.4. Determination of Final Capacity Zones.**

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

**III.13.2.4. Forward Capacity Auction Starting Price.**

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.
III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price
specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.
A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.
An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.
The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability
will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual
reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, 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. For de-list bids, this review and update will follow ISO’s filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the
Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no
event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).
III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5.2, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ISO New England:** A resource seeking to avail itself of the recovery mechanism provided in this Section 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, 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 III.13.2.5.2.5.1(c), 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.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for
which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the
resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price
Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity
Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion
terminate and the status of the resource, or portion thereof, will be converted to retired on the date of
retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-
Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity
Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer
the relevant Capacity Supply Obligation of the resource to another resource through one or more
approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or
reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to
retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of
retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the
status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent
with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has
submitted a Non-Price Retirement Request and the request is not approved because the resource is
determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource
subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law
coincident with the commencement of the Capacity Commitment Period for which the Non-Price
Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO
that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will
be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be
eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection
rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion
thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules
22 and 23 of the OATT.
(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]
III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.7.9 (Capacity Carry Forward Rule), or where payments are set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).


Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.
The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. **Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.**

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. **Capacity Clearing Price Floor.**

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.
(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorating not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.
At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that
price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone’s Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.
III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.
Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9. Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.
The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.
III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest of Pool Capacity Zones system-wide, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each-modeled export-constrained Capacity Zone, the lesser of the Capacity Zone’s Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity-Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest of Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest of Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply $7.025/kW-month during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).
(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply $7.025/kW-month.

III.13.2.8.1.2. System-Wide Inadequate Supply.
The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply $7.025/kW-month during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the...
Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);
(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) $7.025/kW-month during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) $7.025/kW-month.

III.13.2.9. [Reserved.]

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3.  Conduct of the Forward Capacity Auction.
The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price
associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. **Step 2: Compilation of Offers and Bids.**
The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a “New Capacity Offer”) indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round’s prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round’s prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource’s full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource’s full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource’s Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.
(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be $P_S$ and $P_E$, respectively. Let the $m$ prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor’s supply curve, for all prices strictly less than $P_S$ but greater than or equal to $P_E$, shall be taken to be:

$$S(p) = \begin{cases} 
q_0, & \text{if } p > p_1, \\
q_1, & \text{if } p_2 < p \leq p_1, \\
q_2, & \text{if } p_3 < p \leq p_2, \\
\vdots & \vdots \\
q_m, & \text{if } p \leq p_m.
\end{cases}$$

where, in the first round, $q_0$ is the resource’s full FCA Qualified Capacity and, in subsequent rounds, $q_0$ is the resource’s quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource’s New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource’s summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of
that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface’s transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources.** Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource’s FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource’s New Resource Offer Floor Price, such that the resource’s designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round’s relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource’s Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b).
Where a resource elected pursuant to Section III.13.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering.** Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity
Resource pursuant to Section III.13.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource’s location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource’s location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource’s location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics.** Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO’s satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

### III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the “Total System Capacity”) shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the
Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone’s Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface’s approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) Import-Constrained Capacity Zones.

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone’s Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-
Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) Rest-of-Pool Capacity Zone. For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) Export-Constrained Capacity Zones. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone’s Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above
are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).
(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency
Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.
The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.
III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price.
specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

**III.13.2.5.2.3. Dynamic De-List Bids.**

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

**III.13.2.5.2.4. Administrative Export De-List Bids.**

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

**III.13.2.5.2.5. Bids Rejected for Reliability Reasons.**

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability
will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual
reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, 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. For de-list bids, this review and update will follow ISO’s filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the
Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. **Compensation for Bids Rejected for Reliability Reasons.**

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource’s Permanent De-List Bid as accepted for the Forward Capacity Auction. 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. 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 Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. 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 subject to refund while the rate is reviewed. In no
event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability.** If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing 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 Existing Generating Capacity Resources retained for reliability).
III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), 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 ISO New England: A resource seeking to avail itself of the recovery mechanism provided in this Section 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, 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 III.13.2.5.2.5.1(c), 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.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for
which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.
(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]
III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.7.9 (Capacity Carry Forward Rule), or where payments are set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).


Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.
The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. **Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.**

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. **Capacity Clearing Price Floor.**

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.
(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource’s payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorating not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.
At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that
price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface’s approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone’s Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.
III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.
Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource’s location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9. Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.
The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.
If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.
In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.
III.13.2.8.1.1. **Inadequate Supply in an Import-Constrained Capacity Zone.**

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, “New Capacity Required” shall mean the Capacity Zone’s Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; system-wide, “New Capacity Required” shall mean the Installed Capacity Requirement (net of HQICCs), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid $7.025/kW-month during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.
(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to $7.025/kW-month.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid $7.025/kW-month during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) $7.025/kW-month.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity
Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) $7.025/kW-month; or (2) the price in the export-constrained Capacity Zone.

### III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is less than twice the amount of New Capacity Required; or

(iii) any Market Participant’s total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant’s potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing...
Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) $7.025/kW-month during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) $7.025/kW-month.

III.13.2.9. [Reserved.]
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EXECUTIVE SUMMARY

Status Report of Current Regulatory and Legal Proceedings
as of December 4, 2013

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 6, 2013 was circulated. New matters/proceedings since the last report are preceded by an asterisk **. Page numbers precede the matter description.

### I. Complaints

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<tr>
<td>1</td>
<td>FCM Administrative Pricing Rules Complaint (EL14-7)</td>
<td>Nov 12-27&lt;br&gt;Parties intervene&lt;br&gt;Nov 12&lt;br&gt;Nov 15&lt;br&gt;Nov 19&lt;br&gt;Nov 27&lt;br&gt;ISO requests extension of time to Nov 27 to file response&lt;br&gt;NEPOOL files comments in response to extension request; NGrid, NU, CMEEC/MMWEC/NHEC support requested extension; NEPGA opposes request&lt;br&gt;FERC grants extension of time to Nov 27 to file responses and comments&lt;br&gt;ISO-NE files response; NEPOOL, Algonquin &amp; Maritimes Pipelines file comments; CMEEC/MMWEC/NHEC, CT AG, CT Agencies, CT OCC, MA AG, NECPUC, NESCOE, NGrid, and NU file protests; Calpine, EnerNOC, EPSA, Exelon, PSEG file supporting comments</td>
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<tr>
<td>1</td>
<td>FERC-Directed Changes to Fuel Cost Recovery for Certain Reliability Reponses (EL13-72; ER13-2149)</td>
<td>Nov 7&lt;br&gt;FERC accepts the ISO’s compliance proposal, effective Jun 25, 2013; FERC denies rehearing of <em>Dominion Fuel Cost Recovery Order</em></td>
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### II. Rate, ICR, FCA, Cost Recovery Filings

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<tr>
<td>5</td>
<td>FCA8 Qualification Informational Filing (ER14-329)</td>
<td>Nov 12-20&lt;br&gt;NEPOOL, NESCOE, NRG, NU, Blue Sky West, CPV Towantic, Dominion, GDF Suez intervene&lt;br&gt;Nov 20&lt;br&gt;NEPGA submits comments; PSEG and Exelon submit protests; NGrid submits waiver request already filed in ER14-311</td>
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<tr>
<td>6</td>
<td>ICR, HQICCs and Related Values - 2017/2018 Power Year (ER14-328)</td>
<td>Nov 14-25&lt;br&gt;Exelon, Dominion, NESCOE, NU intervene</td>
</tr>
<tr>
<td>6</td>
<td>2014 NESCOE Budget (ER14-91)</td>
<td>Nov 21&lt;br&gt;FERC accepts changes to fund NESCOE’s 2014 operations</td>
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<tr>
<td>7</td>
<td>2013/2014 Winter Reliability Program Bid Results Filing (ER13-2266)</td>
<td>Nov 12&lt;br&gt;Nov 13&lt;br&gt;Nov 27&lt;br&gt;Dec 2&lt;br&gt;TransCanada moves to lodge ISO Markets Committee presentation&lt;br&gt;FERC accepts compliance filing&lt;br&gt;NGrid challenges TransCanada motion to lodge&lt;br&gt;FERC issues tolling order affording it additional time to consider TransCanada request for rehearing of <em>Bid Results Order</em></td>
</tr>
<tr>
<td>8</td>
<td>RCM Add’l Cost Recovery: Dominion (ER13-1291)</td>
<td>Nov 8&lt;br&gt;FERC accepts Dominion’s Aug 16 compliance filing identifying regulatory costs to be recovered by Dominion</td>
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### III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

| * 8 | Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463) | Nov 25<br>ISO submits filing; comment date Dec 16<br>Nov 26- Dec 4<br>APPA, Brookfield, EPSA, Footprint, Maine OPA, TransCanada intervene |
### IV. OATT Amendments / TOAs / Coordination Agreements

| * 14 | **Order 764 Compliance Changes** (ER14-375) | Nov 12 | ISO, NEPOOL, PTO AC, CSC, SSPs jointly file **Order 764 Compliance Changes** |
|      |                                             | Dec 3  | Exelon, NYISO intervene |

| 15   | **Order 1000 Compliance Filing** (ER13-193; ER13-196) | Nov 15 | ISO and PTO AC jointly file **Order 1000 May 17 Compliance Order Changes**; comment date Dec 16, 2013 |

### V. Financial Assurance/Billing Policy Amendments

| * 16 | **FCM Non-Commercial Capacity Changes to Financial Assurance Policy** (ER14-487) | Nov 27 | ISO and NEPOOL jointly file changes |
|      |                                             | Dec 3  | ISO withdraws Nov 27 filing |
|      |                                             | Dec 4  | ISO and NEPOOL jointly re-file changes |

### VI. Schedule 20/21/22/23 Changes

| * 16 | **Schedule 21-NU: LCRAs (Emera, Capital Power)** (ER14-465 et al.) | Nov 26 | NU files Emera LCRAs and cancellation of Capital Power LCRAs; comment date Dec 17 |

| 17   | **Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS** (ER12-2304) | Nov 13 | GMP submits Settlement to resolve all disputes in these proceedings |
|      |                                             | Dec 2  | Settlement Judge Johnson sets deadline for filing initial comments at Dec 13; reply comments, Dec 23 |

### VII. NEPOOL Agreement/Participants Agreement Amendments

*No Activity to Report*
## VIII. Regional Reports

| *18| New England Simultaneous Import Limits (AD10-2) | Nov 20 | ISO-NE submits the 2012 limits for the ISO-NE market and the CT Import Interface and SWCT Import Interface geographic submarkets |
| 18| Capital Projects Report - 2013 Q3 (ER14-85) | Nov 21 | FERC accepts Report |

## IX. Membership Filings

| *19| December 2013 Membership Filing (ER14-497) | Nov 27 | New Member: BTG Pactual Commodities; Termination: AEP Energy; comment date Dec 18 |
| 19| November 2013 Membership Filing (ER14-247) | Nov 26 | FERC accepts Footprint Power Salem Harbor Dev., Pioneer Hydro; Stetson Holdings; and Town Square Energy memberships; eKapital Investments; Reliable Power, LLC; and URI terminations |

## X. Misc. - ERO Rules, Filings; Reliability Standards

| *19| FFT Report: November 2013 (NP14-6) | Nov 27 | NERC files Report |
| *19| New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations) (RM14-1) | Nov 15 | NERC files new Standard |
| 20| NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12) | Nov 21 | FERC issues NOPR proposing to approve proposed revisions to TOP-006-3 filed in RM13-12 but to remand changes to the remaining TOP and IRO Standards filed in RM13-14 and RM13-15; comment date Feb 3, 2014 |
| 22| Order 788: Retirement of Reliability Standard Requirements: P 81 Project (RM13-8) | Nov 21 | FERC issues final rule approving retirement of 34 Reliability Standard requirements and withdrawal of 41 FERC directives that remained outstanding but had otherwise been addressed |
| 23| Order 791: Version 5 CIP Reliability Standards (-002 through -011) (RM13-5) | Nov 22 | FERC issues final rule approving the Version 5 Critical Infrastructure Protection Reliability Standards |
| 24| 2014 NERC/NPCC Business Plans and Budgets (RR13-9) | Nov 22 | NERC submits compliance filing required by Nov 1 order |

## XI. Misc. - of Regional Interest

| *25| 203 Application: NRG Kendall / Veolia ENH (EC14-33) | Nov 22 | NRG requests authorization for the sale of NRG Kendall to Veolia ENH; comment date Dec 16 |
| 25| 203 Application: Edison Mission / NRG (EC14-14) | Nov 7-20 | Parties intervene |
| 26| 203 Application: Capital Power/Emera (Bridgeport & Tiverton) (EC13-151) (Rumford) (EC13-152) | Nov 14 | FERC authorizes the sale of Rumford, Tiverton and Bridgeport to Emera and the transfer of a Capacity Supply Agreement from CP Energy Marketing to Emera Transactions consummated |
| *27| SGIA – CMP/MMWAC (ER14-451) | Nov 22 | CMP files non-conforming SGIA; comment date Dec 13 |
27 Bangor Hydro (Emera Maine) Notice of Succession to MPS OATT (ER14-218) Nov 19 MPS intervenes

27 SGIA – NGrid / Vuelta Solar (ER14-183) Nov 26 NGrid files non-conforming SGIA to govern the interconnection of Vuelta’s 5 MW photovoltaic East Brookfield, MA generating facility; comment date Nov 15

28 E&P Agreement CMP/Western Maine Renewables (ER14-35) Nov 21 FERC accepts E&P Agreement, effective

28 VELCO Floyd Project Cost Recovery Deferral (ER14-12) Nov 22 FERC authorizes VELCO to defer for future recovery costs associated with the VELCO Floyd Project


29 Burlington Elec. Dept. Termination of Mandatory PURPA QF Purchase Obligation from Chace Mill Hydro. Project (QM13-4) Nov 13 FERC grants Burlington’s request to terminate its mandatory PURPA purchase obligation with respect to the Chace Mill project

XII. Misc. - Administrative & Rulemaking Proceedings

30 Zero Rate Reactive Power Rate Schedules (AD14-1) Nov 26 FERC issues notice that a staff-led workshop will be held Dec 11 from 1:30pm to 4pm at the FERC; agenda to follow.

30 RTO/ISO Centralized Capacity Markets (AD13-7) Nov 27 FERC extends post-technical conf comment date to and including Jan 8, 2014

31 Order 792: Revisions to Pro Forma SGIA and SGIP (RM13-2) Nov 22 FERC issues final rule amended its pro forma SGIP and pro forma SGIA; effective date Feb 3, 2014

XIII. Natural Gas Proceedings

34 Order 787: Gas/Electric Operational Info Sharing (RM13-17) Nov 15 FERC issues final rule amending its regulations to provide explicit authority to interstate natural gas pipelines and transmission utilities to share non-public, operational information with each other; effective Dec 23, 2013

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

36 Orders 1000 and 1000-A (12-1232) Nov 15 Parties file Reply briefs

36 FCM Re-Design (12-1060) Nov 19 Oral argument before D.C. Circuit Court of Appeals panel
MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates
FROM: Patrick M. Gerity, NEPOOL Counsel
DATE: December 4, 2013
RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission (“FERC”), state regulatory commissions, and the Federal Courts and legislatures through December 4, 2013. If you have questions, please contact us.¹

I. Complaints

- FCM Administrative Pricing Rules Complaint (EL14-7)

  As previously reported, the New England Power Generators Association (“NEPGA”) filed, on October 31, 2013, a complaint asking the FERC (i) to determine that the Tariff provisions that set capacity prices during Insufficient Competition and Inadequate Supply and the Capacity Carry Forward Rule are creating unreasonable and unduly discriminatory price disparities between new and existing capacity resources; and (ii) to direct that the recommended revisions to the ISO Tariff be implemented (“Complaint”). The substance of the Complaint (the Exelon Proposal) was considered, but not supported, at the October 4, 2013 Participants Committee meeting. NEPGA requested that the proposed Market Rule revisions be made effective so that they are in place prior to FCA8 (or February 3, 2014). At the request of the ISO, and following comments by NEPOOL, supporting comments by CMEEC/MMWEC/NHEC, NGrid, and NU, and a protest by NEPGA, the FERC granted a one week extension of time, to November 27, for the ISO’s answer to and any comments on the Complaint.

  The ISO filed its response to the Complaint on November 27. Comments were filed by NEPOOL and jointly by Algonquin & Maritimes Pipelines. Protests were filed by CMEEC/MMWEC/NHEC, CT AG, CT Agencies, CT OCC, MA AG, NECPUC, NESCOE, NGrid, and NU. Calpine, EnerNOC, EPSA, Exelon, and PSEG filed comments supporting the Complaint. This matter is pending before the FERC.

  If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- FERC-Directed Changes to Fuel Cost Recovery (EL13-72; ER13-2149)

  FERC-initiated 206 proceeding (EL13-72). As previously reported, the FERC initiated, in response to Dominion’s fuel cost recovery filing summarized below (see ER13-1291 below), a Section 206 proceeding finding Section III.A.15 of Appendix A to Market Rule 1 “unjust, unreasonable, unduly discriminatory or preferential, because it does not provide resources an adequate opportunity to recover costs incurred to comply with [ISO] directives to ensure reliability in instances when their supply offers were not mitigated.”² Accordingly, the FERC directed the ISO to submit, revisions to Appendix A that “allow resources to submit a

¹ Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the “Second Restated NEPOOL Agreement”), the Participants Agreement, or the ISO New England Inc. Transmission, Markets and Services Tariff (the “ISO Tariff”).

section 205 filing for cost recovery, including fuel and variable operation and maintenance costs for the resource, in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule. This provision will be in addition to the current provisions allowing cost recovery when a resource is mitigated or when a supply offer was submitted at the energy offer cap.” The FERC indicated that its intention is for Market Rule 1 to provide enough flexibility to allow for cost recovery by resources that respond under extraordinary circumstances like those faced by the New England Market on February 8 and 9, 2013. The changes directed should be “sufficiently restrictive to discourage anticompetitive offering behavior but still allow for cost recovery” in extraordinary circumstances where, for example, “a resource submits an offer based on one fuel type but is required to run on another or cannot burn natural gas based on an Operation Flow Order restriction.” The refund effective date was set at June 25, 2013. For reasons described in prior reports, Dominion requested clarification and/or rehearing of the Dominion Fuel Cost Recovery Order.

On November 7, the FERC denied Dominion’s request, and unless the FERC orders are challenged in federal court, this matter will be concluded.

### August 9 Compliance Filing (ISO Proposal) and NEPOOL Alternative (ER13-2149)

As previously reported, the ISO (on August 13) and NEPOOL (on August 20) filed alternative proposals in response to the Dominion Fuel Cost Recovery Order. On November 7, the FERC accepted the ISO’s proposed compliance revisions, effective June 25, 2013, finding that the ISO’s proposed revisions satisfied its compliance directive. The FERC noted that the “triggers proposed here will help ensure that necessary cost recovery will be available when appropriate, and only when appropriate.” In accepting the ISO’s proposal, the FERC rejected requests for broader recovery, including NEPOOL’s proposal, indicating that “the cost recovery provisions directed in [the Dominion Fuel Cost Recovery Order should] be triggered in situations involving critical reliability needs and extraordinary circumstances, which would not necessarily include every event raised by protestors.” Any challenges to the November 7 rehearing order will be due on or before December 9. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

### NEPGA Resource Performance Obligations Complaint (EL13-66)

As previously reported, the FERC, on August 27, granted in part and denied in part this complaint by NEPGA. NEPGA filed its formal complaint on May 17, 2013, alleging that the ISO impermissibly re-interpreted the Tariff to impose a firm fuel obligation on all capacity resources. In the NEPGA Order, the FERC found that the Tariff imposes a strict performance obligation on capacity resources and that capacity resources may not take economic outages, including outages based on economic decisions not to procure fuel or transportation. The NEPGA Order also found that “a demonstrated inability to obtain natural gas or transportation may legitimacy affect whether a resource is physically available,” where lack of physical availability is not a Tariff violation. Addressing related enforcement matters, the FERC indicated that it would not pursue any pending enforcement referrals from the ISO that are based solely on an alleged inability to procure natural gas. On September 26, 2013, NEPGA challenged the NEPGA Order. The ISO answered

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3 Id. at P 28.

4 The notice of the initiation of the proceeding and refund effective date was published in the Fed. Reg. on June 25, 2013 (Vol. 78, No. 122) p. 38,027.


7 Id. at P 35.

8 Id. at P 36.

the NEPGA request for rehearing on October 15. On October 24, the FERC issued a tolling order affording it additional time to consider the NEPGA rehearing request, which remains pending before the FERC.

**Informational Filing (Factors in Tariff Violation Determination).** The NEPGA Order directed the ISO, on or before September 26, 2013, to submit in an informational filing and post on its website a non-exhaustive list of factors to be used in the determination of a Tariff violation. The ISO submitted that filing and posted that list\(^{10}\) on September 26. Although the informational filing was not noticed for public comment, NEPGA submitted a protest on October 4, asserting that the Informational Filing “goes against the substance of the NEPGA Order and “further underscores the need for a Tariff standard to be established on generator performance obligations”. NEPGA requested that the FERC order the ISO to “file the IMM’s written explanation of material factors under Section 205 of the Federal Power Act, subject to parties’ rights to notice and comment, and Commission approval.” On October 8, Verso Paper filed comments supporting NEPGA’s protest. The ISO answered the NEPGA protest on October 15. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **NESCOE FCM Renewables Exemption Complaint (EL13-34)**

  Rehearing of the FERC’s February 12, 2013 order denying NESCOE’s FCM Renewable Exemption Complaint\(^ {11}\) was requested and remains pending before the FERC. As previously reported, NESCOE instituted this December 28, 2012 complaint in response to the ISO’s December 3, 2012 FCM compliance filing (see ER12-953 in Section III below) that implemented buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO’s proposed Minimum Offer Price Rule (“MOPR”) would likely exclude from the FCM new renewable resources developed pursuant to state statutes and regulations, and thereby result in customers being forced to purchase more capacity than is necessary for resource adequacy and proposed an alternative renewables exemption (the “Renewables Exemption Proposal”). In denying the Complaint, the FERC found that “NESCOE has failed to meet its burden under section 206 to demonstrate that ISO-NE’s MOPR is unjust, unreasonable or unduly discriminatory” as applied to the New England Capacity Market.\(^ {12}\) The FERC declined to set the case for hearing, and therefore denied the motion to consolidate this proceeding with the FCA8 Revisions Compliance Filing proceeding (ER12-953),\(^ {13}\) on which it concurrently issued an order conditionally accepting in part and dismissing in part the ISO’s proposed compliance filing (see Section III below). Rehearing was requested by NESCOE, the CT PURA, and the MA DPU on March 14. On March 29, NEPGA filed an answer challenging NESCOE’s request for rehearing. On April 15, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Base ROE Complaint (2012) (EL13-33)**

  This Complaint, as well as all of the answers and comments submitted in this proceeding, remain pending before the FERC. As previously reported, Environment Northeast (“ENE”), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition (“NICC”, and together, the “2012 Complainants”) filed an additional complaint regarding the return on equity (“Base ROE”) used in calculating formula rates for transmission service in the ISO’s Open Access Transmission

\(^{10}\) The list is posted on the ISO website under the Market Monitoring and Mitigation section: http://www.iso-ne.com/markets/mktmonmit/rpts/other/factors_imm_considers_in_eval_physical_avail_of_fuel_for_gen_res.pdf.


\(^{12}\) Id. at P 32.

\(^{13}\) Id. at P 30.
Tariff (“OATT”), seeking to reduce the Base ROE from the still effective 11.14% to 8.7%. 2012 Complainants acknowledged that the Base ROE is already the subject of ongoing hearing procedures in EL11-66 (see below) but offered the following six reasons for the docketing of a further complaint addressing the Base ROE: (1) the FERC has held that the pendency of a section 206 investigation into a public utility’s ROE does not immunize that ROE from investigation through a second section 206 complaint proceeding; (2) promoting the Congressionally-directed symmetry of remedies as between FPA §§ 205 and 206 (i.e. a fair symmetry requires that 2012 Complainants be free to file a complaint requesting further rate decreases based on later common equity cost data without regard to the status of prior complaints since TOs could file at any time for an increase); (3) this complaint would ensure the FERC could set an ROE below the 9.2% requested in EL11-66 if the evidence leads there; (4) to reset the New England Transmission Owners (“TOs”) zone of reasonableness through updated proxy group analysis; (5) greater assurance that their consent would be required to complete an ROE settlement; and (6) to establish a further 15-month refund period.

Interventions were filed by NEPOOL, AIM, CT AG, CT OCC, CT PURA, EMCOS, MA AG, MOPA, MPUC, TEC, and the VT DPS. On January 16, the TOs filed their answer, asserting that the FERC should dismiss the Complaint as contrary to Section 206’s 15-month refund limitation and that the Complaint failed to show that the TOs’ Base ROE is unjust and unreasonable. TOs argue that evidence relevant to their cost of capital for 2013 and beyond will only be relevant to this Complaint. MMWEC and NHEC filed joint comments supporting the complaint and urging the FERC to grant the relief requested therein and establish the earliest possible refund effective date. Substantively, MMWEC/NHEC provided additional evidence to counter TO arguments that they face substantial payment “risks” in connection either with the provision of transmission service or the construction of new facilities. On January 31, 2013, 2012 Complainants answered the TOs January 16 answer. The request to consolidate this proceeding with EL11-66, as well as the complaint, answers, and comments are pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaint (2011) (EL11-66)**

As previously reported, Trial Judge Cianci issued his initial decision on August 6, 2013 finding unjust and unreasonable the 11.14% ROE currently used in calculating formula rates for transmission service in the OATT, and finding that the ROE should be 10.6% for the October 2011 through December 2012 “locked in/refund period” and 9.7% from January 2013 forward, subject to further updating or modification by the FERC. By way of reminder, the FERC established hearing and settlement judge procedures following a complaint by a number of State, consumer, and consumer advocate parties (the “2011 Complainants”) seeking a FERC order reducing the 11.14% Base ROE to 9.2% “due to changes in the capital markets since the Bangor Hydro proceeding.” After settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful and terminated, these proceedings proceeded to now-completed hearings before Judge

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14 TOs are Bangor Hydro, CMP, National Grid, New Hampshire Transmission (“NHT”), NSTAR, NUSCO on behalf of its operating company affiliates CL&P, WMECO, and PSNH, UI, Unitil and Fitchburg, and Vermont Transco.

15 EMCOS or the “Eastern Massachusetts Consumer-Owned Systems” are Braintree, Hingham, Reading, and Taunton.


17 *Martha Coakley, Mass. Att’y Gen. et al., 139 FERC ¶ 61,090 (2012) (“Base ROE Complaint Order”). The Base ROE Complaint Order was not challenged and is final.


Cianci. Briefs on exceptions to the initial decision were filed by Complainants, TOs, EMCOS, and FERC Trial Staff on September 20. Briefs opposing exceptions were filed by the same parties on October 24, 2013.20 If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings


  On December 3, 2013, the ISO and NEPOOL jointly filed materials that identify the Installed Capacity Requirement (“ICR”), Local Sourcing Requirements (“LSR”), Maximum Capacity Limits (“MCL”) (collectively, the “ICR-Related Values”) and Hydro Quebec Interconnection Capability Credits (“HQICCs”) for the third annual reconfiguration auction (“ARA”) for the 2014/2015 Capability Year to be held March 1, 2014, the second ARA for the 2014/2015 Capability Year to be held in August 2014, and the first ARA for the 2015/2016 Capability Year to be held in June 2014. The ICR-Related Values and HQICCs were supported by the Participants Committee through the approval of the November 8, 2013 Consent Agenda. A February 1, 2014 effective date was requested. Comments on this filing are due December 24, 2013. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA8 Qualification Informational Filing (ER14-329)**

  On November 5, 2013, the ISO submitted its informational filing (the “FCA8 Informational Filing”) for qualification in FCA8. The ISO is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by the ISO for the upcoming Forward Capacity Auction (“FCA”) at least 90 days prior to each auction. FCA8 is scheduled to begin February 3, 2014. The Informational Filing contained the ISO’s determinations that four Capacity Zones, Maine, Connecticut, NEMA, and Rest of Pool, will be modeled for FCA8. The Informational Filing reported that there will be 35,877 MW of existing capacity in FCA8 competing with 2,126 MW of new capacity under a procurement limit of 33,855 MW (ICR minus HQICCs). The ISO reported also that there were a total of 7,851 MW of de-list bids, 1,907 MW of which were later converted into Non-Price Retirement Requests. A list of the 98 Resources for which a Non-Price Retirement Request was submitted, and the status of the associated reliability review, is included in the transmittal letter. The identity of the de-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E.

  Interventions were filed by NEPOOL, NESCOE, NRG, NU, Blue Sky West, CPV Towantic, Dominion, and GDF Suez. NEPGA submitted comments (i) stating that the IMM mitigated a significant percentage of FCA8 generator static de-list bids, suggesting a disconnect between the actual costs and risk thresholds necessary for a Market Participant to assume a Capacity Supply Obligation (“CSO”) and those that, in the IMM’s opinion should, be allowed in a de-list bid, and (ii) asking that the ISO “explain its reasons for each rejected de-list bid after the … FCA8 auction consistent with its obligation to do so under the ISO-NE Tariff.” PSEG protested the filing (i) requesting that, in light of its October 17 memo identifying the possibility of “a deficiency of 1,547 MW below [the Net Installed Capacity Requirement] (“NICR”)” due to the number of retirement notices received, the ISO be directed to supplement the Information Filing to give Participants a clearer picture of available capacity in FCA8, and (ii) requesting that the ISO be directed to revise its Tariff provisions governing the treatment of resources retained for reliability for FCA8, rather than waiting for FCA9 as discussed with Participants. Exelon protested the IMM’s determination with respect to Mystic 7’s static de-list bid and requested that its de-list bid be re-set in accordance with the information provided in its protest. In addition, National Grid submitted in this proceeding, out of an abundance of

20 Errata to the Table of Authorities were filed by Complainants and the TOs on Oct. 25 and 29, respectively.
caution, its November 5 request for limited waiver of the QDN deadlines also filed in ER14-311 (See Section III below). Other requests for waiver of the QDN Deadlines are also included in Section III below.

The FCA8 Informational Filing is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR-Related Values and HQICCs - 2017/2018 Power Year (ER14-328)**

  The ISO and NEPOOL jointly filed, on November 5, 2013, ICRs, HQICCs and related values (Local Sourcing Requirements (“LSR”), Maximum Capacity Limit “MCL”) for the 2017/2018 Capability Year. The values will be used in FCA8 to be held in February 2014. With a 2017/2018 ICR of 34,923 MW (reflecting tie benefits of 1,870 MW) and HQICCs of 1,068/mo., the net amount of capacity to be purchased in FCA8 to meet the ICR will be 33,855 MW. The LSR for the Connecticut and NEMA/Boston Load Zones are 7,319 MW and 3,428 MW, respectively; the MCL for the Maine export-constrained Load Zone is 3,960 MW. The Participants Committee supported the ICR, HQICCs and related values at its October 4, 2013 meeting by way of the Consent Agenda. Interventions were filed by Exelon, Dominion, NESCOE, and NU; no substantive comments were received on or before the November 26 comment date. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **2014 NESCOE Budget (ER14-91)**

  On November 21, the FERC accepted the budget for funding NESCOE’s 2014 operations. As previously reported, the 2014 Operating Expense Budget for NESCOE is $2,158,421. The amount to be recovered reflects true-ups for a 2012 over-collection of $770,714. Accordingly, the NESCOE budget will result in a charge of $.00553 per kilowatt of Monthly Network Load. Unless the November 21 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2014 ISO-NE Administrative Costs and Capital Budgets (ER14-90)**

  As previously reported, the ISO filed for recovery of its 2014 administrative costs (the “2014 Revenue Requirement”) and submitted its capital budget and supporting materials for calendar year 2014 (“2014 Capital Budget”, and together with the 2014 Revenue Requirement, the “2014 ISO Budgets”) on October 15. The 2014 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO Budgets. In the October 15 filing, the ISO reported that the 2014 Revenue Requirement (allowing for measured growth from 2013 levels), after true-up for 2012, is $171.2 million. Of that total, the ISO’s administrative costs (i.e., the 2014 Core Operating Budget) comprise $140.9 million; depreciation and amortization of regulatory assets, $28.4 million; and 2012 true-up, $1.9 million.

  The ISO further reported that the 2014 Capital Budget is $28 million and is comprised of the following (with 2014 projected costs and target completion dates, if available, in parentheses):

  - Intra-day Offers (Q4 2014) ($6 million)
  - CTS (Nov 2015) ($3.8 million)
  - Non-Project Capital Expenditures ($3.7 million)
  - Other Emerging Work Including Strategic Planning Initiatives ($1.57 million)
  - 2014 Issues Resolution Project (Q4 2014) ($1.5 million)
  - FCM Terminations and Retirements (Sep 2014) ($570,100)
  - Cyber Security (TBD) ($550,000)
  - Business Continuity Plan Infrastructure Enhancements Phase III (Q2 2015) ($500,000)
  - Capitalized Interest ($500,000)
  - Quarterly Release Projects 2014 (Quarterly) ($300,000)
  - Wind Integration Phase II (Q4 2015)
The 2014 ISO Budgets were supported by the Participants Committee at its October 4, 2013 meeting. Comments on this filing were due November 5, 2013. A doc-less intervention was filed by NU. NEPOOL filed comments supporting the 2014 Budgets. CT PURA and CT OCC (the “Connecticut State Agencies”) filed a limited protest, asserting that the ISO’s proposed increase in and funding for additional full-time employees (“FTEs”) does not comply with the 2013 Budgets Settlement Agreement and suggesting that the proposed increase and funding for additional FTEs should be postponed until the next budget cycle. On November 18, the ISO answered the Connecticut State Agencies protest, challenging the assertion that the 2014 ISO Budgets do not comply with the 2013 Settlement Agreement and asserting that the funding for additional FTEs cannot wait. This matter is pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **2013/2014 Winter Reliability Program Bid Results Filing (ER13-2266)**

On October 7, the FERC conditionally accepted the list of the Market Participants selected to provide demand response (“DR”) and oil inventory services in the 2013/2014 Winter Reliability Program and the prices they will be paid. The ISO received bids that nearly met its targeted procurement at a total price of $114.3 million. In approximate numbers, the ISO proposed to accept 83% of the targeted MWh at a price of $79 million.


22 The ISO received bids that nearly met its targeted procurement at a total price of $114.3 million. In approximate numbers, the ISO proposed to accept 83% of the targeted MWh at a price of $79 million.

23 Bid Results Order at PP 23, 26-30.

24 Id. at P 31. Essential Power identified an overstatement of its total MWh by 50% (the tank capacity for a shared fuel tank was not pro-rated when reflected in the units’ awards); Exelon inadvertently miscalculated the usable portion of its oil storage tanks.

25 TransCanada asserts that the FERC erred in: (1) failing to determine whether the costs and resulting bid prices are just and reasonable; (2) accepting the bidding results because the ISO failed to comply with its Tariff criteria; and (3) rejecting arguments re: the “excessive disparity” between the Analysis Group’s estimated cost range and the actual price of the program.
in this proceeding an ISO PowerPoint Presentation (the “Winter Solutions Update”) presented at the November 13-14 Markets Committee meeting as relevant to the question as to whether the costs of the Winter 2013-14 Winter Program are just and reasonable and whether it was just and reasonable to allocate the costs of the Program to load serving entities. National Grid challenged the appropriateness of that submission on November 27. And, on December 2, the FERC issued a tolling order affording it additional time to consider the TransCanada rehearing request, which remains pending before the FERC.

Compliance Filing. As previously reported, the ISO submitted, on October 15, the compliance filing directed by the Bid Results Order. That compliance filing was accepted by the FERC on November 13.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- RCM Add’l Cost Recovery: Dominion (ER13-1291)

On November 8, the FERC accepted Dominion’s August 16 compliance filing that identified $30,392.20 in regulatory costs incurred and to be recovered by Dominion in connection with this proceeding. Unless the November 8 order is challenged, this aspect of the proceeding (the remainder summarized in Section I above (ER13-2149)) will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- FCA1 Results Remand Proceeding (ER08-633)

As previously reported, the DC Circuit issued on December 23, 2011, a per curiam order that PSEG’s May 2010 petition for review be granted, remanding the FERC’s orders in this proceeding for further consideration. In particular, the FERC must (i) determine whether PSEG’s position (that it should receive the full (unprorated) floor price for all its resources that it could not prorate) would be an appropriate way to interpret the then-existing Market Rules and, if not, (ii) respond to PSEG’s objections that any contrary result would result in “undue discrimination” and would be “inconsistent with the fundamental policy goals” of FCM. On October 15, 2012, PSEG filed a motion requesting that the FERC issue an order on remand directing the ISO to pay PSEG the full FCA floor price without further delay (for PSEG, the difference totaling $2.8 million plus interest). The ISO filed on October 31, 2012 an answer to PSEG's October 15 motion. On November 1, 2012, Connecticut Generators submitted comments supporting PSEG’s request and a few of the Connecticut Generators moved to intervene out-of-time. This matter remains pending before the FERC.

### III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)

On November 25, the ISO filed revisions to the FCM administrative pricing rules that (i) address what the ISO identified as a “gap” in the Insufficient Competition rules; (ii) sets an administrative rate of $7.025/kW-month to be applied if there is Insufficient Competition (as the ISO proposed to redefine it) or

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Inadequate Supply in FCA8; and (iii) make additional clarifying changes to the FCM administrative pricing rules (collectively, the “FCM Pricing Rule Changes”). The ISO proposed that the FCM Pricing Rule Changes become effective on January 24, 2014. The ISO stated that the FCM Pricing Rule Changes were being submitted as an “Exigent Circumstances” filing. Comments on this filing are due on or before December 16, 2013. Thus far, interventions have been filed by APPA, Brookfield, EPSA, Footprint, Maine OPA, and TransCanada. This matter has been more fully described in materials posted for discussion under Agenda Item 10A at the December 6 Participants Committee annual meeting.

- **Waiver Request - Capacity Qualification Deadlines: Blue Sky West (ER14-364)**
  On November 8, Blue Sky West LLC (“Blue Sky West”) requested a limited, one-time waiver of the FCA8 Capacity Qualification Deadlines to enable the IMM to consider the additional data submitted by Blue Sky West after the relevant deadlines which will correct an error that resulted in an overstated New Resource Offer for Blue Sky West’s 186 MW on-shore wind facility in Maine. On November 25, the ISO submitted comments indicating that it does not oppose the waiver request and requesting an order on or before January 17, 2014, should the FERC grant the waiver, to allow the revised values to be reflected in the FCA8 software. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pggerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: CSG (ER14-356)**
  On November 8, Conservation Services Group (“CSG”) requested a limited, one-time waiver of the FCA8 Capacity Qualification Deadlines to enable the IMM to consider the additional data submitted by CSG after the relevant deadlines which it believes will support its position that three of its Combined Heat & Power (“CHP”) projects in Massachusetts that are included in its aggregated FCM resources should be qualified for a New Resource Offer Floor Price below the FCA8 $15.819/kW-month Offer Review Trigger Price. On November 22, the ISO submitted comments indicating that it does not oppose the waiver request and requesting an order on or before January 17, 2014, should the FERC grant the waiver, to allow the revised values to be reflected in the FCA8 software. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pggerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: National Grid (ER14-311)**
  On November 5, National Grid requested a limited waiver of the Capacity Qualification Deadlines for FCA8 to enable the IMM to consider the additional data submitted by National Grid after the relevant deadlines which it believes will support its position that two Combined Heat & Power (“CHP”) projects, one in Rhode Island and one in Massachusetts, should be qualified for a New Resource Offer Floor Price below the FCA8 $15.819/kW-month Offer Review Trigger Price. On November 25, the ISO submitted comments indicating that it does not oppose the waiver request and requesting an order on or before January 17, 2014, should the FERC grant the waiver, to allow the revised values to be reflected in the FCA8 software. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pggerity@daypitney.com).

- **CSO Terminations: Pawtucket (ER14-270)**
  Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on November 1 to terminate a CSO for Resource No. 326 held by Project Sponsor Pawtucket Power Holding Company LLC (“Pawtucket”). The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the amount of financial assurance provided by

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29 Pursuant to Section 11.2 of the Participants Agreement, the ISO may file Market Rule changes in “Exigent Circumstances” before full consultation with NEPOOL through the FERC-approved Participant Processes. “Exigent Circumstances” are defined as circumstances where “ISO determines in good faith that (i) failure to immediately implement a new Market Rule, Operating Procedure, Reliability Standard, provision of the Information Policy, Non-TO OATT Provision or Manual would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the New England Markets, and (ii) invoking the procedures set forth in Section 11.1, 11.3 or 11.4 would not allow for timely redress of ISO’s concerns.”
Pawtucket with respect to the CSO. NEPOOL intervened on November 12. No comments on this filing were submitted on or before the November 22 comment date and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Terminations: Entergy (ER14-266)**
  Also on November 1, the ISO filed to terminate a portion of the CSO for Resource No. 1630 held by Project Sponsor Entergy Nuclear Power Marketing LLC (“Entergy”). The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the amount of financial assurance provided by Entergy with respect to the portion of the CSO terminated. NEPOOL intervened on November 12. No comments on this filing were submitted on or before the November 22 comment date and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **eTariff Corrections: Sections I.2, III.1, and III.F (ER14-172)**
  On October 24, the ISO submitted various corrections to its eTariff. The corrections revise Section I.2 (to restore terms accepted in ER13-1742), the Section III Table of Contents, Section III.1 (fixing a typographical error), and Section III Appendix F (to restore auditing revisions from ER13-323). NEPOOL intervened on November 12. No comments were submitted on the initial correction filing. However, the ISO amended its filing on November 19 (to include a redline inadvertently omitted) and supplemented its filing on November 27 (to include corrections to the Section III Table of Contents), with comments due December 10 and 18, respectively. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Terminations: EnerNOC (ER14-29)**
  The FERC accepted on November 19 the ISO filing terminating 54 CSOs held by Project Sponsor EnerNOC. The ISO indicated that it would draw down the amount of financial assurance provided by EnerNOC with respect to the CSOs terminated. Unless the November 19 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Reliability Commitment Mitigation Revisions (ER13-2397)**
  On November 15, the FERC accepted revisions to Market Rule 1 Appendix A to modify the market power mitigation rules that apply to Supply Offers for resources that are committed out-of-merit to address a local reliability need (the “Reliability Commitment Mitigation Revisions”) jointly submitted by the ISO and NEPOOL. The revisions were accepted September 18, 2013, as requested. As previously reported, the Reliability Commitment Mitigation Revisions were proposed in response to the IMM’s determination that the previous mitigation test for local reliability commitments had resulted in conduct that the IMM viewed as manipulation. Unless the November 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Energy Market Offer Flexibility Changes (ER13-1877)**
  As previously reported, the FERC conditionally accepted, on October 3, 2013, energy market enhancements designed to provide Market Participants greater flexibility in structuring and modifying their


31 Specifically, the changes (1) will permit the cost-related parameters of a Supply Offer or a Demand Bid for a Dispatchable Asset Related Demand (“DARD”) to be modified after the initial Reserve Adequacy Analysis (“RAA”) process is completed; (2) will permit submission of cost-related parameters of a Supply Offer or a Demand Bid for a DARD that vary by hour; (3) modify self-schedule implementation to reflect the ability to submit hourly Supply Offers and change Supply Offers in Real-Time; (4) permit submission of negative offers as low as negative $150/MWh for External Transactions and
Supply Offers in the Day-Ahead and Real-Time Energy Markets (the “Offer Flexibility Changes”). The Offer Flexibility Changes were accepted effective as of December 1, 2014, as requested. In accepting the Offer Flexibility Changes, the FERC noted a few potential inconsistencies between the ISO’s intended application of the proposed revisions, including the lock-out provisions, and the actual proposed Tariff language. Accordingly, the FERC conditioned its acceptance upon the submission of a compliance filing that reconciles the proposed Tariff language with the ISO’s statements concerning application. Although the compliance filing would have been due December 2, NEPOOL and the ISO requested an extension of time, to and including January 17, 2014, to allow for the Markets Committee to review and make its recommendations concerning the compliance changes at its November and December meetings, and the Participants Committee to consider and vote on such recommendations at its January 10, 2014 meeting. That request was granted on October 30. The compliance changes are currently scheduled for consideration at the December 10-11 Markets Committee meeting. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter 2013/2014 Reliability Program (ER13-1851)**

As previously reported, the FERC conditionally accepted the Winter Reliability Program on September 16, to be effective September 6, 2013 through February 28, 2014. The FERC conditioned its acceptance of the Program on the allocation of Program costs to RTLO rather than Regional Network Load, and on the removal of the specific dates added to Section III.K.2 in the Emergency Amendments Filing (related to the timing for public comments, and issuance of a FERC order, on the Bid Results filing). In directing the change in cost allocation, the FERC found that that costs of the Program should be allocated to RTLO “[b]ecause real-time load is the primary beneficiary, and the primary cost-driver, of the Winter Reliability Program.” The FERC found unpersuasive the arguments that it would be more appropriate to allocate Program costs to Regional Network Load. As for the second condition, while the FERC recognized the urgency of the winter reliability concerns that led to the proposed specific dates, the FERC did not find that the record supported provisions binding it to issue an order by a specific date (or include a comment deadline for a proceeding that is already underway and pending before the FERC). Rehearing of the 2013/2014 Winter Reliability Program Order was requested by EPSA and TransCanada. On November 12, 2013, the FERC

the energy Blocks for a Supply Offer, Demand Bid, Increment Offer and Decrement Bid; (5) reflect conforming changes to Appendix A mitigation rules consistent with these changes; and (6) reflect clarification and clean-up changes.

32 ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014 (Oct. 3, 2013) (“Offer Flexibility Changes Order”). The Offer Flexibility Changes Order was not challenged and is final and unappealable.


34 The FERC also noted its expectation that the ISO would, as it committed to do in the proceeding, make a separate filing at the end of the Winter Reliability Program to relocate the market monitoring changes contained in Appendix K to elsewhere within Market Rule 1. Those changes to satisfy that commitment are under consideration at the Markets Committee.

35 Id. at P 70.

36 Id. at P 71. The filing parties asserted that Program cost allocation to Regional Network Load was more appropriate because (i) the Program is a discrete, out-of-market solution similar to a Gap RFP, and (2) the timing of the Program is such that it would have been difficult for LSEs to anticipate the costs and include them in their contracts. The FERC disagreed that the Program, which specifically addresses generation related concerns (resource performance coupled with the region’s increased dependence on natural gas), is akin to a Gap RFP, which addressed transmission-related concerns. Further, the FERC also found unpersuasive the arguments that the timing of the Program warranted allocation to Regional Network Load (either because an RTLO allocation would impose unavoidable costs on LSEs on short notice or increase risk premiums). Citing the Winter 2005/2006 order, the FERC stated that “LSEs “voluntarily assume Real-Time Load Obligation when entering into bilateral contracts with end-use customers[;]” those “contracts contain inherent risk associated with unforeseeable future costs, and we would expect that risk to be captured in bilateral contracts between LSEs and end-use customers.” (Id. at P 76).
issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

As noted in Section II above (2013/2014 Winter Reliability Program Bid Results Filing (ER13-2266)), TransCanada submitted for inclusion in this proceeding as well an ISO PowerPoint Presentation (the “Winter Solutions Update”) presented at the November 13-14 Markets Committee meeting as relevant to the question as to whether the costs of the Winter 2013-14 Winter Program are just and reasonable and whether it was just and reasonable to allocate the costs of the Program to load serving entities. National Grid challenged the appropriateness of that submission on November 27.

**Compliance Filing.** On November 13, the ISO accepted the Market Rule changes jointly submitted by the ISO and NEPOOL in response to the 2013/2014 Winter Reliability Program Order.

If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Notice of Effective Date: CSO Bilateral Transaction Enhancements (ER13-585)**

  On October 18, the ISO provided notice that the rule changes to allow Market Participants to submit CSO Bilaterals before the current submission windows open (in Section III.13.5), accepted December 19, 2012, will become effective on December 17, 2013. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Conforming Changes Reflecting PRD Full Integration (ER12-1627)**

  The ISO’s March 15, 2013 compliance filing in this proceeding remains pending before the FERC. As previously reported, the FERC, on January 14, 2013, accepted in part, and rejected in part, the ISO’s proposed changes, filed April 26, 2012, to make the FCM Market Rules consistent with the PRD full integration rules (currently scheduled to become effective on June 1, 2017).\(^{37}\) The FERC also accepted the proposed revisions to Appendix E of Market Rule 1 to become effective June 1, 2017, as requested, and granted the ISO’s request to delay implementation of the Fully Integrated rules to June 1, 2017. The FERC found just and reasonable the “must-offer requirement for demand response resources with a capacity supply obligation in ISO-NE’s FCM,”\(^{38}\) agreed that “the proposal will assist in correcting inefficiencies inherent in the current capacity market design, and will provide substantial benefits to many parties,”\(^{39}\) and found the “proposal will be beneficial to both demand response providers and wholesale electricity customers.”\(^{40}\) However, the FERC rejected the ISO’s proposal regarding net supply (contained in sections III.E.7.3 and III.13.7.1.5.2), without prejudice to a future filing revising Tariff language to clarify its rules regarding DR resources that provide capacity through both demand reductions and behind-the-meter generation.\(^{41}\) Noting its concerns with other aspects of the filing, the FERC conditioned its acceptance of certain changes subject to explanations to be included in the 60-day compliance filing.

**60-Day Compliance Filing.** The ISO submitted, on March 15, 2013, a compliance filing providing the directed explanations and addressing the changes rejected in the January 14 Order. Protests on that compliance filing were submitted on April 5 by DR Supporters\(^{42}\) and Verso Paper. DR Supporters protested the absence of any provision in the ISO Tariff or Manuals that provide details about the factors that the ISO and the IMM will consider in evaluating energy offers from DR Resources, though they “emphasize that they do not contest the

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\(^{38}\) *Id.* at P 27.

\(^{39}\) *Id.* at P 28.

\(^{40}\) *Id.* at P 29.

\(^{41}\) *Id.* at PP 44-46.

\(^{42}\) “DR Supporters” are Comverge, EnerNOC, NICC, Wal-Mart, and the IECG.
reasonableness or level of specificity provided in aggregate by ISO-NE in its written assertions regarding how it will go about evaluating offers or the various factors it anticipates may be considered in ‘legitimate offer strategies’”. For its part, Verso Paper stated that “ISO-NE’s proposed ‘know it when they see it’ process for monitoring and evaluating demand response offers will not work in practice for all demand response providers, and ISO-NE’s explanation for retaining a 10 day refreshment period fails to recognize that, with a must-offer requirement, 10 days is too short a time to refresh the baseline.” On April 19, the ISO answered the DR Supporters and Verso Paper protests. On April 30, Verso Paper answered the ISO’s April 19 answer. The ISO’s compliance filing and protests and answers related thereto remain pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

  As previously reported, the FERC, on February 12, 2013, conditionally accepted in part and rejected in part the revisions to the FCM and FCM-related rules in the Tariff (“FCA8 Revisions”) filed by the ISO and the PTO AC.43 The **FCA8 Revisions Order** accepted the following aspects of the FCA8 Revisions as compliant with its prior FCM Orders: the ISO’s offer review trigger prices;44 unit specific offer review;45 the ISO’s proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports’ treatment under MOPR;46 no exemptions to MOPR for new Self-Supplied Resources;47 the application of mitigation to all new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;48 $1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;49 and a number of other additional revisions.50 The **FCA8 Revisions Order** rejected: the ISO’s proposed methodology for reducing the offer floor of an uncleared resource that has already achieved commercial operation at the time of an FCA (directing the ISO to submit a revised proposal that subjects a resource to an offer floor until it has demonstrated that it is needed by the market)51; the ISO’s request to model only 4 capacity zones for FCA8. Two requests for rehearing of the **FCA8 Revisions Order** were filed on March 15, 2013, one by MMWEC, NHEC, APPA, NEPPA, and NRECA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MMWEC et al. request. On April 15, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Tie Benefits Calculation and Allocation (ER08-41)**

  The ISO’s January 14, 2010 update in this proceeding remains pending. As previously reported, the ISO filed, on January 14, 2010, an update to the joint ISO/NEPOOL November 26, 2008 report52 regarding the plan to

44 FCA8 Revisions Order at PP 37-38.
45 Id. at P 53.
46 Id. at P 70.
47 Id. at P 80.
48 Id. at P 97.
49 Id. at P 126.
50 Id. at P 127.
51 Id. at PP 63-64.
52 The 2008 Tie Benefits Report indicated that the stakeholder process would begin early during the second quarter of 2009 and would be completed in time for any proposed Market Rule 1 or other Tariff changes to be filed with
study and develop proposals to resolve issues related to the modeling of internal transmission constraints and tie benefits associated with individual lines. In the January 14, 2010 Update, the ISO proposed to comprehensively review and attempt to resolve during 2010 all outstanding and identified tie benefits issues (including the so-called “Reserved Issues”, issues raised during 2009 stakeholder meetings, and tie benefits-related issues raised in Docket No. ER10-438) through a NEPOOL stakeholder process and to make a filing with the FERC on or before a date that will allow any related Market Rule or Tariff changes to be effective in time for FCA5 (covering the 2014/2015 Capacity Commitment Period). At its February 5, 2010 meeting, the Participants Committee considered and voted on the ISO’s January 14 proposal. The ISO’s Proposal received 43.25% support from the Participants Committee. On February 8, 2010, NEPOOL filed comments reflecting the results of that consideration and vote. NESCOE submitted a motion to intervene out-of-time and comments on February 12, 2010. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

### IV. OATT Amendments / TOAs / Coordination Agreements

- **Order 764 Compliance Changes (ER14-375)**
  
  On November 12, the ISO, NEPOOL, the PTO AC, CSC, and the Schedule 20A service providers (“SSPs”) jointly filed revisions to Section II of the ISO Tariff to comply with the requirements of Orders 764 and 764-A (the “Order 764 Compliance Changes”). Specifically, the Order 764 Compliance Changes revise Schedule 22 (LGIA) of the OATT. This transmittal letter also explains how FERC-approved deviations from the pro forma OATT already meet the requirements and policy goals of Order 764 and are “consistent with or superior to” those provisions. The Participants Committee supported the Order 764 Compliance Changes at its August 2, 2013 meeting. Comments on this filing were due on or before December 3, 2013. None were filed. Interventions were filed by Exelon and the NYISO. This matter is pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Order 1000 Interregional Compliance Filing (ER13-1960; ER13-1957)**
  
  On July 10, the ISO, NEPOOL and the PTO AC jointly filed revisions to Sections I and II of the ISO Tariff to comply with the interregional coordination and cost allocation requirements of Orders 1000 and 1000-A (the “Order 1000 Interregional Compliance Changes”) (ER13-1960). In addition, the ISO, on behalf of itself, NYISO and PJM, filed an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol (“Amended Protocol”) as part of its compliance changes (ER13-1957). The Order 1000 Interregional Compliance Changes include (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I. The Order 1000 Interregional Compliance Changes and the Amended Protocol were supported by the Participants Committee at its June 27 Summer Meeting. On August 7, the FERC extended the comment deadline on these filings to and including September 9, 2013. Doc-less motions to intervene were filed by a number of New England parties in both proceedings, including Dominion, Exelon, PPL, PSEG, and NEPOOL (in the Protocol proceeding (in which it was not a filing party)). On August 26, NEPOOL filed comments supporting the Protocol. NEPOOL added that “From a stakeholder perspective, stakeholder input into revisions to the Protocol as it evolves over time would be easier and more likely to be taken into account if it were made part of the individual regional tariffs of each of the Northeast ISOs rather than existing solely as a stand-alone three-party agreement”. On September 9, NESCOE submitted comments generally supporting the filings, but reserving the right to further comment on these filings should the substance of the changes be modified as a result of further FERC (see ER13-193 and ER13-196 below).
or federal court proceedings. Public Interest Organizations\(^{53}\) raised concerns that the Protocol and related amendments “do not meet certain of the transparency and cost allocation aspects of [Order 1000]’s minimum requirements.” On September 24, the ISO answered Public Interest Organizations’ and NEPOOL’s comments. These matters are now pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Order 1000 Compliance Filing (ER13-193; ER13-196)**
  
  Rehearing of the FERC’s May 17, 2013 order on the region’s Order 1000 compliance filing\(^{54}\) (described in previous Reports) remains pending. As previously reported, the Order 1000 Compliance Order accepted the ISO-NE/PTO compliance filing as partially complying with Order 1000, but required changes to the compliance proposal. The primary change was the elimination of the Right of First Refusal (“ROFR”) and the establishment of competitive transmission development for all regional transmission projects (with an exception to the elimination of the ROFR for transmission needed for reliability within three years of the needs assessment determination and subject to certain other limiting criteria). Additionally, the Order 1000 Compliance Order required that the public policy transmission proposal be revised to: (i) make the ISO, rather than the New England states, the entity that evaluates and selects which transmission projects will be built to meet transmission needs driven by public policy; and (ii) include an ex ante default cost allocation method, transparent to all stakeholders, developed in advance of particular transmission facilities being proposed, rather than leaving it to the states to decide cost allocation on a project-specific basis after particular projects are proposed. While requiring these fundamental changes to the public policy transmission part of the filing, the Order 1000 Compliance Order also allowed for the NESCOE-driven proposal for both selection of projects and cost allocation to remain in the tariff as a complementary process for voluntary transmission projects alongside the Order 1000-compliant process. A more detailed summary of the Order 1000 Compliance Order was circulated to the Participants Committee on May 20, 2013. On June 17, the ISO, LS Power, PTO AC and NESCOE each filed requests for clarification and/or rehearing of the Order 1000 Compliance Order. On June 28, the ISO answered LSP Power’s request concerning the effective date for the Order 1000 compliance changes. On July 16, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

- **November 15 Order 1000 Compliance Order Changes**. On November 15, the ISO and the PTO AC jointly submitted proposed revisions to Sections I and II of the ISO Tariff and to the Transmission Operating Agreement (“TOA”) (the “Compliance Revisions”) to comply with the FERC’s May 17, 2013 Order 1000 Compliance Order. The revisions included planning revisions (addressing competitive processes for developing new regional transmission projects), cost allocation revisions (regarding the allocation of costs for Public Policy Transmission Projects), and TOA revisions. The Planning Revisions and the Cost Allocation Revisions filed by the ISO and PTO AC were considered but not supported by the Participants Committee at its November 8 meeting. Comments on the November 15 filing are due on or before December 16, 2013. NEPOOL’s comments to be submitted before the December 16 comment date will include for FERC consideration the Participants Committee-recommended Planning Revisions.

If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Capability Resource Ratings (ER11-2216)**

  Action on MMWEC’s request for rehearing of the FERC’s January 28, 2011 Capability Clarifications Order\(^{55}\) continues to be deferred. As previously reported, the revisions to Tariff accepted by

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\(^{53}\) “Public Interest Organizations” are Conservation Law Foundation, Environment Northeast, Natural Resources Defense Council, Pace Energy and Climate Center, and the Sustainable FERC Project.

\(^{54}\) *ISO New England Inc.*, 143 FERC ¶ 61,150 (2013) (“Order 1000 Compliance Order”).

the FERC were described as clarifying the controlling order/hierarchy of documents relied upon by the ISO to establish the energy and capacity output levels for certain Existing Generating Capacity Resources (“Capability Clarifications”). The filing parties (the ISO and the PTO AC) asserted that the Capability Clarifications addressed what the FERC found ambiguous in a July 2010 order in EL10-58,\(^56\) namely, the controlling order of approval documents and data used by the ISO to establish the CNR Capability of an existing generating resource. The Capability Clarifications were considered by the Participants Committee at its October 18, 2010 meeting, but ultimately not supported. In accepting the Capability Clarifications, the FERC addressed protests filed by Dominion, MMWEC, and PSEG. The FERC found that the changes were consistent with, and not a collateral attack on, the FERC’s July 2010 order, and provide equal treatment to resources seeking to change capacity limits. In addition, the FERC was also persuaded that interconnection agreements are a more reliable means of determining the CNR Capability ratings, and declined to direct the use of the MW ratings in the CELT Report. MMWEC requested rehearing of the Capability Clarifications Order on February 24, 2011, but requested the FERC defer action on the merits of the rehearing request until completion of the process under which the CNR rating for Stony Brook is currently under review. MMWEC stated that if it was able to secure adequate relief, it would so inform the FERC and withdraw the rehearing request; if not, it would ask the FERC to address the merits of its rehearing request. The FERC issued on March 24, 2011 a tolling order affording it additional time to consider the MMWEC rehearing request, which remains pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FCM Non-Commercial Capacity Changes to Financial Assurance Policy (ER14-525; ER14-487)**

The ISO and NEPOOL jointly re-submitted on December 4, 2013 changes related to financial assurance (“FA”) for Non-Commercial Capacity in the FCM. The changes: (i) required Designated FCM Participants to provide additional FA prior to offering Non-Commercial Capacity in an FCA; (ii) strengthened the incentives to bring Non-Commercial Capacity to commercial status; (iii) employed a market price based-value, rather than a fixed value, to calculate FA for Non-Commercial Capacity; and (iv) eliminated the requirement that Non-Commercial Capacity that has not cleared in an FCA provide FA when acquiring CSOs through reconfiguration auctions or bilateral transactions. Although the changes were first filed on November 27 (ER14-487), they were subsequently withdrawn on December 3 to allow the new filing to accurately reflect the separate effective dates associated with implementation of the changes which, other than for those described in (iv) (which are to take effect March 28, 2014), are to take effect for resources that clear in FCA9 or later. Comments on the re-filed changes will be due on or before December 26. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NU: LCRAs (Emera, Capital Power) (ER14-465 et al.)\(^57\)**

On November 26, the NU Companies submitted (1) a Notice of Cancellation of NU’s Localized Costs Responsibility Agreement (“LCRA”) with CP Energy Marketing (US) LLC (“Capital Power”); and (2) a new LCRA by and between the NU Companies and Emera Energy Services Subsidiary No. 5 LLC (“Emera”). The Agreements were filed to reflect the fact Emera acquired the Bridgeport Energy facility from Capital Power. A December 1, 2013 effective date was requested for each of the Agreements. Comments on these filings are due


\(^{57}\) Because 3 NU Companies’ eTariffs are involved, the LCRAs related to the Bridgeport Energy generated 3 dockets: ER14-465 (CL&P); ER14-466 (PSNH); and ER14-467 (WMECO).
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on or before December 17. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NU: LCRA (CTMEEC, Wallingford) (ER14-324 et al.)**

  On November 5, the NU Companies submitted (1) a Notice of Cancellation of NUSCO’s LCRA with Connecticut Municipal Electric Energy Cooperative (“CMEEC”); (2) a LCRA by and between the NU Companies and Connecticut Transmission Municipal Electric Energy Cooperative (“CTMEEC”); and (3) a new LCRA by and between the NU Companies and the Town of Wallingford Department of Public Utilities, Electric Division (“Wallingford”). In addition, the Northeast Utilities Service Company (“NUSCO”), as agent for CL&P, submitted an agreement with Wallingford under which CL&P will provide scheduling and dispatch services to Wallingford through the Connecticut Valley Exchange (“CONVEX”) dispatch center and amendments to the existing CMEEC and CTMEEC CONVEX Agreements. The Agreements were filed to reflect the fact that Wallingford will be procuring transmission service directly from the ISO, and to the extent necessary, from other New England TOs, rather than through CMEEC. A January 1, 2014 effective date was requested for each of the Agreements. No comments on these filings were submitted on or before the November 26 comment date and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NU: Elimination of Unreserved Use Penalties (ER14-258)**

  On November 1, NUSCO and the ISO filed amendments to Schedule 21-NU to eliminate unreserved use penalties and the associated penalty distribution methodology. The NU Companies concluded that the Schedule 21-NU unreserved use penalties no longer serve the purpose for which they were intended, create an unnecessary burden on customers associated with Schedule 21-NU point-to-point transmission service, and should be eliminated. An effective date of January 1, 2014 was requested. No comments on this filing were submitted on or before the November 22 comment date and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LGIA – BHE/Oakfield Wind Farm (ER14-63)**

  On October 9, BHE filed a non-conforming LGIA (LGIA-ISON/E/BHE-12-02) under Schedule 22 of the ISO Tariff to govern the interconnection of Evergreen Wind II’s 147.6 MW wind farm in Oakfield, Maine (the “Oakfield Project”). BHE reports that the LGIA does not conform to the **pro forma** LGIA because the revised LGIA is a four-party agreement (reflecting the separate ownership of certain interconnection facilities by Maine Gen Lead). An October 11, 2013 effective date was requested. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304)**

  As previously reported, the FERC accepted on September 24, 2012, the revised schedules and notices of cancellation filed by Green Mountain Power (“GMP”) in this proceeding, but suspended the provisions, subject to refund, and established hearing and settlement judge procedures.59 In its September 24 order, the FERC stated that its “preliminary analysis indicates that Applicants’ proposed Schedules 21-GMP and 20A-GMP and notices of cancellation have not been shown to be just and reasonable, and … raise issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed in the hearing and settlement judge

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58 Because 3 NU Companies’ eTariffs are involved, the cancellation of the CMEEC LCRA generated 3 dockets: ER14-312 (CL&P); ER14-313 (PSNH); and ER14-315 (WMECO); the CTMEEC LCRA: ER14-318 (CL&P); ER14-319 (PSNH); and ER14-320 (WMECO); and the Wallingford LCRA: ER14-321 (CL&P); ER14-322 (PSNH); and ER14-324 (WMECO). The Convex Agreements were filed in ER14-326 (Wallingford); ER14-327 (CMEEC); and ER14-330 (CTMEEC).

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procedures we order.”60 Requests for clarification and/or rehearing of the GMP Merger Order requested by VEC and WEC (“Cooperatives”)61 were denied on February 25, 2013.62 Also on February 25, the FERC accepted GMP’s October 31, 2012 compliance filing, rejecting Cooperatives’ arguments protesting the compliance filing as beyond the scope of the compliance filing proceeding.63

Judge Karen V. Johnson was designated as the settlement judge, and convened two settlement conferences. After a lengthy period of reported negotiation, Green Mountain Power Corporation (“GMP”) submitted on November 13 a Settlement Agreement and Offer of Settlement (“Settlement”) that reportedly resolves all disputes in these proceedings. Pursuant to a December 2 notice issued by Judge Johnson, the deadline for filing initial comments is December 13, 2013; the deadline for filing reply comments, December 23, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- New England Simultaneous Import Limits (AD10-2)
  On November 20, 2013, the ISO filed with the FERC the 2012 simultaneous import limits (“SIL”) for the New England-wide geographic market and the Connecticut Import Interface (“CT Import Interface”) and the Southwest Connecticut Import Interface (“SWCT Import Interface”) geographic submarkets to assist New England sellers in preparing their updated market power indicative screens and Delivered Price Test (“DPT”) analyses to be submitted pursuant to Order 697.

- Capital Projects Report - 2013 Q3 (ER14-85)
  On November 21, the FERC accepted the ISO’s October 15 Capital Projects Report and Unamortized Cost Schedule covering the third quarter (“Q3”) of calendar year 2013 (the “Report”). As previously reported, Report highlights included the following new projects: Alternative Technologies and Regulation Market ($2,015,700); FCM Terminations and Retirements Project ($779,900); and Control Room Visualization ($284,100). Projects reported to have significant changes included (i) Simultaneous Feasibility Test and Market System Upgrade ($551,800 decrease); (ii) Wind Integration ($350,100 increase); (iii) HR and Payroll System Replacement ($100,600 increase); (iv) Web Enhancements Phase II ($140,000 decrease); (v) FCA8 Project ($125,000 decrease); and (vi) Business Intelligence Phase III ($106,000 decrease). Unless the November 21 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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60 Id. at PP 21-22.

61 Cooperatives asserted that the FERC failed to appropriately address the Mobile Sierra claim contained in VEC’s Protest and further explained in WEC’s Answer. WEC separately requested that the FERC correct three statements in the GMP Merger Order concerning positions taken by WEC.


63 Green Mountain Power Corp., 142 FERC ¶ 61,147 (2013). The FERC noted that Cooperatives’ raised the same issues in their joint request for rehearing of the GMP Merger Order, submitted in Docket No. ER12-2304-001, and their arguments will be addressed in that proceeding. Id. at n. 7.
Order 755 Regulation Market Progress Reports: 1st Quarterly Status Report (ER12-1643)

Per its commitment in its July 19, 2013 request for an extension of time to October 1, 2014 to implement the regulation Market Rule changes submitted pursuant to Order 755, the ISO submitted on November 1, 2013 its first informational quarterly progress report detailing the efforts made and milestones achieved in implementing the regulation market changes. In the first report, the ISO explained that progress toward implementing the regulation market changes has proceeded within the lower end of the estimated time that would be required to meet the targeted October 1, 2014 effective date, with 3 of the first 8 development stages completed, and the fourth stage, software development, underway. The ISO’s next quarterly progress report is due February 3, 2014. These status reports will not noticed for public comment.

IX. Membership Filings

- December 2013 Membership Filing (ER14-497)
  On November 27, NEPOOL requested that the FERC accept: (i) the membership of BTG Pactual Commodities (Data Only Participant); and (ii) the termination of the Participant status of AEP Energy (Supplier Sector) (Nov 1, 2013). Comments on this filing are due on or before December 18, 2013.

- November 2013 Membership Filing (ER14-247)
  On November 26, the FERC accepted: (i) the memberships of Footprint Power Salem Harbor Development (Generation Sector, Group Seat); Pioneer Hydro Electric Co., Inc. (AR Sector, RG Sub-Sector, Small Group Member); Stetson Holdings, LLC [Related Person to First Wind Energy Marketing et al., AR Sector, RG Sub-Sector]; and Town Square Energy, LLC [Related Person to Twin Cities Power, Supplier Sector]; (ii) the termination of the Participant status of eKapital Investments LLC (Supplier Sector)(Oct 1, 2013); Reliable Power, LLC (Supplier Sector)(Nov 1, 2013); and University of Rhode Island (End User Sector, Oct 1, 2013); and (ii) the name changes of NRG Canal LLC (f/k/a GenOn Canal, LLC) and NRG Kendall LLC (f/k/a GenOn Kendall, LLC).

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- FFT Report: November 2013 (NP14-6)
  NERC submitted on November 27, 2013, its Find, Fix, Track and Report (“FFT”) informational filing for the month of November 2013. The November FFT resolves 28 possible violations of 12 Reliability Standards that posed a risk minimal risk to bulk power system (“BPS”) reliability, but which have since been remediated. The 14 Registered Entities involved each submitted a mitigation activities statement of completion. These filings are for information only and will not be noticed for public comment by the FERC.

- New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations) (RM14-1)
  On November 14, 2013, NERC filed for approval a new Reliability Standard that requires Bulk-Power System owners and operators to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances consistent with the reliable operation of the BPS. As of the date of this report, a comment date has not been set. The lack of a comment date or NOPR notwithstanding, interventions have to this point been filed by APPA, EEI, Exelon, and NRECA.

64 Only possible violations that pose a minimal risk to Bulk-Power System reliability are eligible for FFT treatment. See N. Am. Elec. Reliability Corp., 138 FERC ¶ 61,193 (2012) at PP 46-56.
• NOPR: Revised Reliability Standards: MOD-025-2, MOD-026-0, MOD-027-0, PRC-019-1 and PRC-024-1 (RM13-16)

On September 19, 2013, the FERC issued a NOPR proposing to approve changes to MOD-025-2 (Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability) and the following 4 new Reliability Standards:65

- MOD-026-1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions);
- MOD-027-1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions);
- PRC-019-1 (Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection); and
- PRC-024-1 (Generator Frequency and Voltage Protective Relay Settings).

FERC also proposed to approve, with modifications, the associated implementation plans, Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”). Finally, the FERC proposed to approve, as requested, the retirement of MOD-024-1 (Verification of Generator Gross and Net Real Power Capability) and MOD-025-1 (Verification of Generator Gross and Net Reactive Power Capability) prior to the effective date of MOD-025-2. FERC stated that the revised and new Standards will help ensure that verified data is available for power system planning and operational studies by requiring the verification of generator equipment needed to support Bulk-Power System reliability and enhance coordination of important protection system settings. Comments on the NOPR were due on or before November 25, 201366 and were filed by eight parties, including ISO-NE, EEI, and NERC. In its comments, ISO-NE asked the FERC to modify Reliability Standards MOD-026-1 and MOD-027-1 to include generators rated below 100 MVA. ISO-NE asserted that the 100 MVA threshold was too high, would exclude too many new England generating units, and should be lowered to match the “bulk electric system” registration requirement of 20 MVA. This NOPR is pending before the FERC.

• NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)

On November 21, 2013, the FERC issued a NOPR67 proposing (i) to approve NERC’s proposed revisions to Reliability Standard TOP-006-3 (Monitoring System Conditions) filed in RM13-12, but (ii) to remand changes to the following Interconnection Reliability Operations and Coordination (“IRO”) and Transmission Operating (“TOP”) Reliability Standards filed in RM13-14 and RM13-15:

- IRO-001-3 (Reliability Coordination — Responsibilities and Authorities);
- IRO-002-3 (Reliability Coordination – Analysis Tools);
- IRO-005-4 (Reliability Coordination – Current Day Operations);
- IRO-0014-2 (Coordination Among Reliability Coordinators);
- TOP-001-2 (Transmission Operations);
- TOP-002-3 (Operations Planning);
- TOP-003-2 (Operational Reliability Data); and

65 Generator Verification Reliability Standards, 144 FERC ¶ 61,205 (2013).
As previously reported, the changes to TOP-006-3 filed April 5, 2013 are targeted to address the respective monitoring role and notification obligation of Reliability Coordinators ("RCs"), Balancing Authorities ("BAs") and Transmission Operators ("TOPs") by clarifying that TOPs are responsible for monitoring and reporting available transmission resources and that BAs are responsible for monitoring and reporting available generation resources. In addition, the changes confirm that RCs, TOPs, and BAs are required to supply their operating personnel with appropriate technical information concerning protective relays located within their respective areas.

The changes to the IRO Standards were to achieve two important overall reliability benefits: (1) delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) improve system performance by raising the bar on monitoring of Interconnection Reliability Operating Limits ("IROLs") and System Operating Limits ("SOLs") in order to focus monitoring on IROLs and SOLs that are important to reliability.

The changes to the remaining TOP Standards were to upgrade the overall quality of the Standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address Order 693 directives. NERC indicated in its April filing that the proposed TOP Standards are also more efficient than the currently-enforceable TOP Reliability Standards because they incorporate the necessary requirements from the eight currently-effective TOP Reliability Standards (TOP-001-1a, TOP-002-2.1b, TOP-003-1, TOP-004-2, TOP-005-2a, TOP-006-2, TOP-007-0, TOP-008-1) and the PER-001-0.2 Reliability Standard into three cohesive, comprehensive Reliability Standards that are focused on achieving a specific result.

Because the proposed TOP and IRO Reliability Standards were interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involved similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the FERC addressed all three proposals together in the one NOPR. Although the FERC acknowledged that the proposed TOP and IRO Reliability Standards contain some improvements over the current Standards, concerns that the changes would create reliability gaps in the Standards that are critical to reliable operation of the BPS resulted in the proposed remand of the proposed TOP Standards.69 The FERC went on to explain that given the interrelationship between the TOP and IRO Reliability Standards and that NERC requests that both sets of standards be addressed together, we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.70

Comments are the Nov 21 NOPR are due on or before February 3, 2014.71

- **NOPR: Revised Reliability Standard: BAL-003-1 (RM13-11)**

On July 18, the FERC issued a NOPR proposing to approve changes to BAL-003 (Frequency Response and Frequency Bias Setting), as well as the associated definitions, implementation plan, VRFs, and VSLs,

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68 The changes in proposed PRC-001-2 were administrative in nature and were limited to removal of three requirements in currently-effective PRC-001-1 that were to be addressed in proposed TOP-003-2.

69 *Id.* at P 4.

70 *Id.*

71 The Nov 21 NOPR was published in the *Fed. Reg.* on Dec. 5, 2013 (Vol. 78, No. 234) pp. 73,112-73,128.
submitted by NERC on March 19, 2013.\textsuperscript{72} NERC stated that the changes respond to FERC directives in Order 693\textsuperscript{73} to develop modifications to BAL-003-0 that: (1) include Levels of Non-Compliance; (2) determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) define the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved. Specifically, the Revised Standard is designed to ensure that each of the Interconnections have sufficient Frequency Response to guard against underfrequency load shedding ("UFLS") due to an event in that Interconnection. NERC requested an effective date that is the first day of the first calendar quarter that is 12 months following the effective date of a Final Rule in this docket. Comments on this NOPR were due September 27, 2013,\textsuperscript{74} and were filed by NERC, BPA, Electricity Consumers Resource Council, jointly by EEI, APPA, NRECA, and EPSA, MISO, ISO/RTO Council, and Arizona Public Service. NERC filed reply comments on October 15, 2013. This NOPR is pending before the FERC.

- \textit{Order 786: TPL-001-4 (footnote ‘b’) (RM13-9; RM12-1)}

On October 17, the FERC approved TPL-001-4.\textsuperscript{75} As previously reported, NERC had a long standing compliance obligation to address FERC concerns with footnote ‘b’.\textsuperscript{76} NERC’s February 28 filing addressed those concerns (by changing the requirements and processes for planned load shed in the event of a single Contingency (identified in a revised footnote 10 included in TPL-001-4)). \textit{Order 786} also approves the consolidation of all of the currently effective TPL Standards (including superseding proposed TPL-001-2, which NERC had proposed in a previous NOPR to remand) into one Standard. Finally, the FERC directed NERC to modify Reliability Standard TPL-001-4 to address the concern that the Standard could exclude planned maintenance outages of significant facilities from future planning assessments and directed NERC to change the TPL-001-4, Requirement R1 Violation Risk Factor from medium to high.\textsuperscript{77} \textit{Order 786} will become effective December 23, 2013.\textsuperscript{78}

- \textit{Order 788: Retirement of Reliability Standard Requirements: P 81 Project (RM13-8)}

On November 21, the FERC approved the retirement of 34 requirements in 19 Standards that NERC indicated were redundant and/or otherwise could be removed with little or no effect on reliability.\textsuperscript{79} In addition, the FERC withdrew 41 directives that remained outstanding that required NERC to develop modifications to Reliability Standards because the identified outstanding directives had either been addressed in some other manner, were redundant with another directive or provided general guidance as opposed to a specific directive.\textsuperscript{80} \textit{Order 788} will become effective [45 days after publication in the Federal Register].\textsuperscript{81}

\begin{footnotes}
\item[72] Frequency Response and Frequency Bias Setting Rel. Std., 144 FERC ¶ 61,057 (July 18, 2013)
\item[73] Order 693 at P 375.
\item[76] See Trans. Planning Rel. Standards, 139 FERC ¶ 61,059 (2012) (“TPL-001-2 NOPR”). The FERC found TPL-001-2 vague and unenforceable because the Standard did not adequately define the circumstance in which an entity can plan for non-consequential load loss following a single contingency.
\item[77] Order 786 at P 3.
\item[79] Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards, Order No. 788, 145 FERC ¶ 61,147 (Nov. 21, 2013) (“Order 788”).
\item[80] Id. at P 2.
\item[81] As of the date of this Report, Order 788 has not been published in the Fed. Reg.
\end{footnotes}
• NOPR: Revised Reliability Standard: PRC-005-2 (RM13-7)

As previously reported, the FERC issued, on July 18, a NOPR proposing to approve changes to PRC-005 (Protection System Maintenance) filed by NERC on February 26, 2013 that: (1) include maximum allowable intervals in PRC-005 for time-based, condition-based, and performance-based maintenance programs; (2) combine PRC-005, PRC-008, PRC-011, and PRC-017 into one Standard; and (3) clarify that it is the equipment owner that will be responsible for completing required maintenance.82 In addition, the FERC seeks clarification and comment on three aspects of PRC-005-2 and proposes to modify one VSL. Comments on this NOPR were due on or before September 23, 2013.83 Comments were submitted by NERC, Bureau of Reclamation, Duke, G&T Cooperatives,84 Idaho Power Company, ITC, and Oncor. On October 30, 2013, NERC submitted an errata to the Implementation Plan for proposed PRC-005-2. The NOPR is pending before the FERC.

• NOPR: Remand of Interpretation of BAL-002-1a (RM13-6)

This May 16 NOPR, which proposes to remand NERC’s proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.85 NERC asserted that the proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard. Specifically, the proposed interpretation would clarify that: (1) a Disturbance that exceeds the most severe single Contingency, regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency. The FERC, however, proposes to remand the proposed interpretation because it believes the interpretation changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations. Comments on the BAL-002-1a Interpretation Remand NOPR were due on or before July 8, 2013,86 and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR is pending before the FERC.

• Order 791: Version 5 CIP Reliability Standards (-002 through -011) (RM13-5)

On November 22, 2013, the FERC approved the Version 5 Critical Infrastructure Protection (“CIP”) Reliability Standards submitted by NERC, which adopt new cyber security controls and extend the scope of the systems that are protected by the CIP Standards.87 The FERC also approved 19 new or revised definitions associated with the CIP version 5 Standards for inclusion in NERC’s Glossary of Terms. In addition, as it proposed in the prior NOPR, the Commission directed NERC to develop modifications to the CIP version 5 Standards to address concerns that limited aspects of the CIP Version 5 Standards are potentially ambiguous and may raise questions regarding the enforceability of the standards. The FERC also directed NERC to submit

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82 Protection System Maintenance Reliability Standard, 144 FERC ¶ 61,055 (July 18, 2013) (“PRC-005-2 NOPR”).


informational filings regarding certain issues during and following implementation of the CIP version 5 Standards. *Order 791* will become effective February 3, 2014.\(^8^8\)

- **Order 773-A**: Revised “Bulk Electric System” Definition and Procedures (RM12-7; RM12-6)

  Other than a pending request for re-hearing of the FERC’s June 13, 2013 order in this proceeding,\(^8^9\) which deferred the effective date for the revised BES definition as approved in *Order Nos. 773\(^{9^0}\) and 773-A*\(^{9^1}\) to July 1, 2014 (rather than July 1, 2013), this proceeding has largely been concluded. The Pacific Northwest Generating Cooperative (“PNGC”) requested re-hearing of the *June 13 Order*, asserting that, in granting the request, the FERC incorrectly stated that utilities must apply the BES definition prior to seeking a local distribution determination from the FERC and, consequently, inappropriately postponed filing of local distribution filings until the BES definition becomes effective. The FERC issued a tolling order on August 7, 2013 affording it additional time to consider the PNGC rehearing request, which remains pending before the FERC. Also, a compliance filing to modify Exclusion E3 of the BES Definition, to remove the 100 kV minimum operating voltage in the local network definition, is expected to be filed in late November 2013.

- **2014 NERC/NPCC Business Plans and Budgets (RR13-9)**

  On November 1, the FERC largely accepted NERC’s proposed 2014 Business Plan and Budget, as well as the 2014 Business Plans and Budgets for the Regional Entities, including NPCC.\(^9^2\) As previously reported, NERC’s proposed 2014 Funding requirement is approximately $52.3 million, representing an overall increase of approximately $2.1 million (3.9%) over NERC’s 2013 Funding requirement. The NPCC U.S. allocation of NERC’s net funding requirement is $3,440,461. NPCC has requested $14.1 million in statutory funding (a U.S. assessment per kWh (2011 NEL) of $0.0000409) and $1.065 million for non-statutory functions. Based on the information contained in the NERC Application, the FERC rejected NERC’s proposal to allocate $3.8 million to “restricted working capital” to offset future liabilities under NERC’s lease agreements. Instead, the FERC directed NERC to submit a compliance filing within 30 days of the November 1 order indicating how NERC will allocate the $3.8 million consistent with NERC’s Working Capital and Operating Reserve Policy. NERC submitted that compliance filing on November 22, and comments on that filing are due on or before December 6, 2013.

- **Market Implications of Frequency Response and Frequency Bias Setting Requirements (AD13-8)**

  On July 18, 2013, the FERC solicited comment on the potential market and commercial impacts of certain of the requirements of the proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) (see RM13-11 above).\(^9^3\) The FERC did not propose changes to proposed Reliability Standard BAL-003-1. Rather, the FERC indicated the comments would inform its consideration and coordination of the requirements of the proposed Standard with tariffs and markets rules subject to its jurisdiction.\(^9^4\) Comments were due on


\(^{9^0}\) *Revisions to ERO Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012) (“Order 773”), order on reh’g and clarification, 143 FERC ¶ 61,053 (2013), order denying reh’g, 144 FERC ¶ 61,174 (2013).


\(^{9^3}\) *Market Implications of Frequency Response and Frequency Bias Setting Reqs.*, 144 FERC ¶ 61,058 (2013).

\(^{9^4}\) *Id.* at P 2.
October 18, 2013. Comments were submitted by NERC, Arizona Public Service, BPA, EEI, EPSA, the Electricity Consumers Resource Council, the Electricity Storage Association (“ESA”), MISO and PJM, and PG&E. This matter is pending before the FERC.

### XI. Misc. - of Regional Interest

- **CFTC Exemption**

  On March 28, 2013, the Commodity Futures Trading Commission (“CFTC”) issued a 142-page final order in response to a February 7, 2012 petition by the RTO/ISOs, including ISO-NE, that exempts from certain provisions of the Commodity Exchange Act (“CEA”) the purchase or sale of specifically defined “financial transmission rights,” “energy transactions,” “forward capacity transactions,” and “reserve or regulation transactions” that are offered or sold in a market administered by one of the petitioning RTOs or ISOs pursuant to a tariff or protocol that has been approved or permitted to take effect by FERC or PUCT, as applicable. To be eligible for the exemption, the specifically defined transactions are required to be entered to by persons who are: (1) “appropriate persons,” as defined in section 4(c)(3)(A) through (J) of the CEA; (2) “eligible contract participants,” as defined in section 1a(18) of the CEA and CFTC regulation 1.3(m); or (3) in the business of (i) generating, transmitting, or distributing electric energy, or (ii) providing electric energy services that are necessary to support the reliable operation of the transmission system. The exemption is subject to the continued effectiveness of acceptable information sharing arrangements between the CFTC and the FERC. The exemption also requires the RTOs and ISOs to keep CFTC requests for information confidential. In addition, the CFTC’s anti-fraud and anti-manipulation authority, and scienter-based prohibitions will continue to apply, and the exemption is subject to certain additional conditions stated within the final order. A more detailed summary of the final order was circulated to the Committee and the Dodd-Frank Working Group on April 5, 2013.

  Changes to the FAP and Information Policy required to comport with the CFTC Order were conditionally accepted August 30, 2013 (see ER13-1875, Section V. above). Additional compliance changes to the FAP were considered at the September 13 meeting, and submitted in a compliance filing submitted that same day (see ER13-1875, Section V above). The April 30, 2012 ISO-NE request for supplemental order clarifying that the contracts, agreements, and transactions entered into under the ISO’s Tariff (including internal bilaterals) are exempt from the Act and CFTC regulations to the same degree and extent as the already relief granted in the March 28 order remains pending. If there are questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **203 Application: NRG Kendall / Veolia ENH (EC14-33)**

  On November 22, NRG North America and NRG Kendall (together, “NRG”) requested approval of a transaction whereby NRG will sell 100% of the common equity interests in NRG Kendall to a joint venture between ISQ Thermal Kendall LLC and Veolia Energy North America Holdings, Inc. (“Veolia ENH”). NRG asked for a FERC order as soon as possible to allow for the transaction to be consummated on December 31, 2013. Comments on this filing are due on or before December 13, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Edison Mission / NRG (EC14-14)**

  On October 25, NRG Energy Holdings Inc. (“NRG”) and Edison Mission Energy (“EME”) and its public utility subsidiaries requested approval of a transaction whereby NRG will acquire substantially all of EME’s assets, including EME’s direct and indirect interests in EME’s public utility subsidiaries and other generation-owning entities, in exchange for cash and stock. Applicants asked for a FERC order by January 31, 2014.

95 A copy of the 391-page “Consolidated Request” was circulated to the Committee by the ISO on Feb. 8, 2012, and is also available at [http://www.iso-ne.com/regulatory/ferc/fed/index.html](http://www.iso-ne.com/regulatory/ferc/fed/index.html).

96 A copy of the supplemental request was circulated to the Committee on Apr. 30, 2012 and is also available at [http://www.iso-ne.com/regulatory/ferc/fed/2012/index.html](http://www.iso-ne.com/regulatory/ferc/fed/2012/index.html).
Comments on this filing are due on or before December 9, 2013. Thus far doc-less interventions have been filed by Bank of New York, PJM Customer Coalition, and PSEG affiliates that are the owners-lessees of certain affected facilities. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

203 Application: Capital Power/Emera (Bridgeport & Tiverton) (EC13-151) (Rumford) (EC13-152)

On November 14, the FERC authorized the sale of 100% of the equity interests in Rumford, Tiverton and Bridgeport to Emera and the transfer of a Capacity Supply Agreement from CP Energy Marketing to Emera (collectively, the “Transactions”). The parties reported that the Transactions were consummated on November 19, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

203 Application: Maine Public Service / Bangor Hydro (EC13-81)

Pending notice that this merger has been consummated, this proceeding has been completed. As previously reported, the FERC authorized the merger of Maine Public Service (“MPS”) into Bangor Hydro (“Applicants”) on July 18, 2013. The merger will result in a single electric utility with operations in both central and northern Maine, but without resulting in the direct interconnection of the facilities currently owned by Bangor Hydro and MPS (which are currently only indirectly interconnected via transmission lines in Canada owned by unrelated entities). Bangor Hydro’s current transmission system will remain under the functional control of the ISO, while that currently owned by MPS will not. In a companion order (ER13-1125), the FERC waived its regulations to permit Bangor Hydro to maintain two OATTs following consummation of the transaction – one for the central Maine transmission lines currently owned by Bangor Hydro, and one for the northern Maine lines currently owned by MPS. Applicants committed to hold harmless transmission and wholesale customers from transaction-related costs for five years. Among other conditions, the BHE/MPS Merger Order required Applicants to notify the FERC within 10 days of the consummation of the merger, which has not yet occurred, but is expected to occur on January 1, 2014. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

203 Application: Boston Gen / Constellation Mystic Power (EC10-85)

Rehearing remains pending of FERC’s December 22, 2010 order authorizing Fore River Development, LLC, Mystic I, LLC, Mystic Development, LLC, and Boston Generating, LLC (together, “Boston Gen”) and Constellation Mystic Power, LLC (“Mystic Power”) to sell five of Boston Gen’s generating facilities (Fore River, Mystic 7, 8, and 9, and Mystic Jet) and certain other assets to Constellation Holdings, Inc. or its designee (in this case, its wholly-owned affiliate Mystic Power). As previously reported, the Bankruptcy Court authorized on November 24, 2010 the sale of the generating facilities and other assets to Constellation (“Sale Order”). Mystic Power notified the FERC that the transaction was consummated on January 3, 2011. On January 21, 2011, NSTAR filed a request for rehearing of FERC’s order authorizing the transaction to correct the common mode failure reliability condition of Mystic 8 and 9. On February 22, 2011, the FERC issued a tolling order affording it additional time to consider NSTAR’s request. On June 3, NSTAR submitted to the FERC additional information to accompany its January 21 request for rehearing. Mystic Power requested on June 20 that the FERC disregard NSTAR’s June 3 filing, and affirm its December 22, 2010 order. NSTAR’s request for rehearing remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

100 Fore River Dev., LLC, 133 FERC ¶ 61,248 (2010).
• **SGIA – CMP/MMWAC (ER14-451)**

On November 22, CMP filed a non-conforming SGIA (IA-CMP-14-01) to govern the interconnection of the 2.1 MW waste-to-energy facility of Mid-Maine Waste Action Corporation (“MMWAC”) in Auburn, Maine, whose current Agreement with CMP will expire at the end of the year. CMP reports that the SGIA does not conform to the *pro forma* SGIA because of modifications to recognize (i) that the ISO is not a party to the LGIA and (ii) the MMWAC facility has been connected to the grid for many years and therefore there has been no new interconnection request or change/break in service with CMP. A January 1, 2014 effective date was requested. Comments on this matter are due on or before December 13, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

• **NSTAR/HQUS Use Rights Transfer Agreement (ER14-244)**

On October 31, NSTAR filed an Agreement between NSTAR and H.Q. Energy Services (U.S.), Inc. (“HQUS”) that transfers, for an additional year, NSTAR’s transmission capacity Use Rights on the HQ Interconnection.¹⁰¹ Once transferred, HQUS may use or market and sell those Use Rights at its sole discretion, consistent with the Restated Use Agreement and/or in compliance with the ISO-NE OATT and OASIS posting requirements. NSTAR retains all of its IRH management committee voting rights, financial obligations and all other rights and responsibilities provided for in its Support Agreements and the Restated Use Agreement that are not directly related to the Use Rights and their exercise by HQUS. A January 1, 2014 effective date was requested. Comments on this filing were due on or before November 21, 2013, but none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

• **Bangor Hydro (Emera Maine) Notice of Succession to MPS OATT (ER14-218)**

On October 29, Bangor Hydro (which will be renamed Emera Maine when, on January 1, 2014, Maine Public Service (“MPS”) will be merged with and into it) filed a notice of its intent to succeed to the MPS OATT, and filed a revised OATT reflecting that succession. As previously reported, the FERC approved the merger of MPS and BHE and waiver of its regulations to permit the successor entity to maintain two OATTs on file with the FERC – one for the former MPS transmission system and one for the former BHE transmission system (*see* EC13-81 above).¹⁰² A January 1, 2014 effective date for the revised OATT was requested. Comments on this filing were due on or before November 19, 2013, but none were filed. MPS intervened on November 19. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

• **SGIA – NGrid / Vuelta Solar (ER14-183)**

On November 26, the FERC accepted a non-conforming SGIA (IA-NGrid-45) filed by New England Power Company (“NGrid”) to govern the interconnection of Vuelta’s 5 MW photovoltaic generating facility (the “Vuelta Plant”), located in East Brookfield, Massachusetts. As previously reported, the Vuelta Plant will sell all of its output to Massachusetts Electric Company pursuant to a power purchase agreement. The SGIA generally conforms to the *pro forma* SGIA set forth in Schedule 23 of ISO’s OATT, with only minor non-conforming modifications to reflect that the ISO is not a party (the ISO having determined that Vuelta Solar’s interconnection subject to the SGIA does not constitute an interconnection request under the OATT and is therefore not subject to Schedule 23 of the OATT). The SGIA was accepted effective as of September 17, 2013, as requested. Unless the November 26 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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¹⁰¹ Pursuant to the “Third Amendment And Restated Use Agreement With Respect To Use Of Quebec Interconnection,” (“Restated Use Agreement”), NSTAR has rights to use a portion of the transfer capability on the Phase I and Phase II high-voltage, direct-current transmission facilities (“HQ Interconnection”), which are known as “Use Rights”. The Agreement continues, with modifications summarized in the filing, the First Transfer Agreement accepted in a series of orders in Docket No. ER09-207. *See NSTAR Elec. Co., 125 FERC ¶ 61,371 (2008).*

- **E&P Agreement CMP/Western Maine Renewables (ER14-35)**
  
  On November 21, the FERC accepted a Design Engineering & Procurement Agreement (“E&P Agreement”) between CMP and Western Maine Renewables, LLC (designated as service agreement CMP-EP-5 under CMP’s eTariff files). The E&P Agreement sets forth the terms and conditions under which CMP will provide engineering and procurement services to Western Maine Renewables in connection with Western Maine’s planned 100 MW wind farm in Moscow, Maine. The E&P Agreement was accepted for filing as of May 21, 2013, as requested. Unless the November 21 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **VELCO Floyd Project Cost Recovery Deferral (ER14-12)**
  
  On November 22, the FERC authorized VELCO to defer for future recovery costs associated with the VELCO Floyd Project (company-wide effort to evaluate and reduce operating costs, streamline processes, and make VELCO a leaner and more efficient business). VELCO was authorized to begin the deferral as of December 31, 2013. Unless the November 22 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **SGIA – CMP/Spruce Wind (ER14-11)**
  
  On November 21, the FERC accepted an amended SGIA between CMP and Spruce Wind, which replaces a previously executed SGIA to reflect the term and milestone dates for the SGIA and correct other errors in the SGIA that provides for the interconnection of Spruce Wind’s 10.2 MW wind turbine generators located along the Woodstock, Maine Spruce Mountain ridgeline. The SGIA was accepted effective October 2, 2013, as requested. Unless the November 21 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **E&P Agreement BHE/First Wind (ER13-2120)**
  
  On November 20, the FERC accepted an E&P Agreement between Bangor Hydro (“BHE”) and First Wind Energy, LLC (designated as service agreement BHE-2 under BHE’s eTariff files). As previously reported, First Wind is planning elective transmission upgrades to certain facilities located where the generation lead line owned by its subsidiary Evergreen Gen Lead, LLC, interconnects with Bangor Hydro’s Keene Road substation and requested that BHE begin certain design, engineering and procurement activities. The E&P Agreement sets forth the terms and conditions under which BHE will provide such services. BHE requested that the E&P Agreement be accepted for filing, conditioned on submission of an executed agreement following MPUC approval (as described in prior filings, the MPUC must approve any agreement between Bangor Hydro and First Wind prior to its execution, in light of the affiliate relationship between Bangor Hydro and certain subsidiaries of First Wind). The E&P Agreement was accepted effective August 8, 2013, as requested. Unless the November 20 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN – __) Constellation**
  
  On October 4, 2013, the FERC issued a notice that Staff has preliminarily determined that Constellation Energy Commodities Group, Inc. violated 18 CFR § 35.41(b) and the parallel provision of the California ISO (“CAISO”) tariff, § 37.5.1, by not providing accurate information to CAISO.

  Recall that Notices of Alleged Violations (“NoVs”) are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff’s conclusions regarding the subject’s conduct. NoVs are designed to increase the transparency of Staff’s nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

  103 See Enforcement of Statutes, Regulations, and Orders, 129 FERC ¶ 61,247 (2009), order on requests for reh’g and clarification, 134 FERC ¶ 61,054 (Jan. 24, 2011).
• MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)

On December 18, 2012, Judge Sterner issued his 374-page initial decision which, following hearings described in previous reports, found at its core that “it is unjust, unreasonable, and unduly discriminatory to allocate costs of Phase Angle Regulating Transformers (“PARs”) of the International Transmission Company (“ITC”) to NYISO and PJM”,104 which the Midwest ISO (“MISO”) and ITC proposed unilaterally to do (without the support of either PJM or NYISO) in its October 20, 2010 filing initiating this proceeding. For a summary of specific findings, please refer to any of the January to June 2013 Reports.

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. Briefs opposing exceptions were filed by the FERC Trial Staff, MISO TOs, NYISO, NY TOs, PJM, and the PJM TOs. On February 25, Joint Applicants moved to strike a portion of the PJM Brief Opposing Exceptions. On March 12, PJM answered Joint Applicants February 25 motion. Since the last report, MISO (now called “Midcontinent Independent System Operator, Inc.”) moved to lodge a portion of OE’s 2012 State of the Markets Report, presented to the FERC on May 16, 2013, which addressed “Phase Angle Regulators Between Michigan & Ontario Enter Service.” Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, PJM TOs. This matter remains pending before the FERC. If there are any questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

• Waiver of Transmission Standards of Conduct: Bangor Hydro Request (TS11-5)

Bangor Hydro’s October 31, 2011 amended waiver request remains pending before the FERC. As previously reported, the FERC denied, without prejudice, Bangor Hydro’s initial request for waiver of the FERC’s Standards of Conduct requirements.105 Bangor Hydro requested a limited waiver from the FERC’s Standards of Conduct requirements,106 to the extent necessary, to permit its transmission function personnel to undertake the actions necessary to re-sell into the New England Market energy from the Rollins Project which the MPUC has mandated it purchase but cannot otherwise sell at retail. The FERC stated that it would revisit its determination if Bangor Hydro brought forward information demonstrating that it met the criteria for waiver set forth in section 358.1(c) and summarized in the order (i.e. a demonstration that Bangor Hydro has no access to information concerning the operation of the transmission facilities by the ISO and that it obtains information about such matters only by viewing the ISO’s OASIS). In response to the BHE Standards of Conduct Order, Bangor Hydro amended its waiver request in 2 respects: First, Bangor Hydro revised its request to apply only to the energy required to be purchased from the Rollins Project and the Exeter Agri-Energy Project. Second, Bangor Hydro committed, as a condition of the waiver (if granted), not to engage in any purchases or sales of wholesale electric capacity or energy except for those required under Maine laws and/or regulations or orders of the MPUC. The MPUC filed comments supporting Bangor Hydro’s amended waiver request on November 15, 2011. This matter remains pending before the FERC.

• Burlington Elec. Dept. Termination of Mandatory PURPA QF Purchase Obligation from Chace Mill Hydro. Project (QM13-4)

On November 13, 2013, the FERC granted the request by Burlington Electric Department (“BED”) filed to terminate its mandatory purchase obligation with respect to the output of a single qualifying facility (“QF”), the Chace Mill Hydroelectric Project, interconnected to its system and owned by Winooski One Partnership.107 As previously reported, BED asserted that the small QF has nondiscriminatory access to the New England Markets (through its affiliates GDF Suez and FirstLight Power Resources Management) and BED should not be obligated to purchase its output, particularly pursuant to a new PURPA contract. BED stated that did not advocate terminating the PURPA requirement with respect to any other Vermont QF. The

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106 See 18 C.F.R. § 358 (2013) et seq.
107 City of Burlington, Vt., 145 FERC ¶ 61,121 (Nov. 13, 2013).
FERC found that Burlington met its burden of showing that Chace Mill has nondiscriminatory access to the ISO-NE markets. Unless the November 13 order is challenged on or before December 13, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings

- Zero Rate Reactive Power Rate Schedules (AD14-1)
  On October 17, 2013, the FERC issued a notice (i) noting that it had found that, on a prospective basis, for any jurisdictional reactive power service (including within-the-deadband reactive power service) provided by both new and existing generators, the rates, terms, and conditions for such service must be pursuant to a FERC-filed rate schedule, even when that rate schedule provides no compensation for such service;108 and (ii) indicating that a staff-led workshop, open to the public at a time and date to be announced, would be held to explore the mechanics of public utilities filing reactive power rate schedules for which there is no compensation. On November 26, the FERC issued a notice that a workshop to be led by FERC staff will be held December 11, 2013 from 1:30pm to 4pm at the FERC. A subsequent notice detailing the topics to be discussed will be issued in advance of the workshop. All interested were encouraged to attend.

- RTO/ISO Centralized Capacity Markets (AD13-7)
  On September 25, 2013, the FERC held a technical conference on centralized capacity markets. The purpose of the technical conference was to consider how current capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The technical conference provided an opportunity to review the market rules and structures at a high level and examine how they are accomplishing their intended goals and objectives. The technical conference focused on the goals and objectives of existing centralized capacity markets (e.g., resource adequacy, long-term price signals, fixed-cost recovery, etc.) and examined how specific design elements are accomplishing existing and emerging goals and objectives. Comments and presentations have been posted in eLibrary under Docket No. ER13-7. On October 25, the FERC issued a notice inviting post-tech conference comments on any or all of questions attached to the Notice regarding capacity markets in the three Northeast Control Areas. Pursuant to a November 27 notice extending the time for comments, comments must now be filed on or before January 8, 2014.

- NOI: Open Access and Priority Rights on Interconnection Facilities (AD12-14; AD11-11)
  As previously reported, the FERC issued a notice of inquiry (“NOI”), on April 19, 2012, seeking comments on whether, and, if so, how, the FERC should revise its current policy concerning priority rights and open access with regard to certain interconnection facilities. The FERC reported that it had, on a case-by-case basis, permitted an owner of interconnection facilities to have priority to capacity over its facilities for its existing use at the time of a third-party request for service. Specifically, in the instance where an owner of interconnection facilities has specific, pre-existing generator expansion plans with milestones for construction of generation facilities and can demonstrate that it has made material progress toward meeting those milestones, the FERC has granted priority rights for the capacity on the interconnection facilities to those future generation projects or expansions as well. Further, an affiliate of the current interconnection facility owner that is developing its own generator projects also may obtain priority rights to the capacity on the interconnection facilities by meeting the “specific plans and milestones” standard with respect to future use, provided that the plans include a future transfer of ownership of the interconnection facilities to such an affiliate. More than 25 parties filed comments on options for addressing priority rights on interconnection facilities, and this matter remains pending before the FERC.

• **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

  On June 26, WIRES\(^{109}\) petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide “greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure.” Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project’s actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. Since the last report, WIRES submitted on October 3 a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

• **Order 792: Revisions to Pro Forma SGIA and SGIP (RM13-2)**

  On November 22, 2013, the FERC amended its *pro forma* Small Generator Interconnection Procedures (“SGIP”) and *pro forma* Small Generator Interconnection Agreement (“SGIA”), originally set forth in Order 2006, to: (1) incorporate provisions that would provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; (2) revise the 2 MW threshold for participation in the Fast Track Process included in section 2 of the *pro forma* SGIP; (3) revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; (4) revise the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection; (5) revise the *pro forma* SGIP and the *pro forma* SGIA to specifically include energy storage devices; and (6) clarify certain sections of the *pro forma* SGIP and the *pro forma* SGIA.\(^{110}\) *Order 792* will become effective February 3, 2014.\(^{111}\)

• **Order 784: 3rd-Party Provision of Ancillary Services; New Electric Storage Technology Accounting and Financial Reporting (RM11-24; AD10-13)**

  As previously reported, the FERC issued *Order 784*\(^{112}\) on July 18, 2013, revising certain aspects of the FERC’s current market-based rate regulations, ancillary services requirements under the *pro forma* OATT, and accounting and reporting requirements in order to foster competition and transparency in ancillary services markets. Specifically, *Order 784* (i) reforms the FERC’s policies governing the sale of ancillary services at market-based rates to public utility transmission providers; (ii) requires each public utility transmission provider

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\(^{109}\) WIRES, the **W**orking group for **I**nvestment in **R**eliable and **E**conomic **e**lectric **S**ystems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website [www.wiresgroup.com](http://www.wiresgroup.com).

\(^{110}\) *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013) (“*Order 792*”).

\(^{111}\) *Order 792* was published in the *Fed. Reg.* on December 5, 2013 (Vol. 78, No. 234) pp. 73,240-73,354.

\(^{112}\) *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 144 FERC ¶ 61,056 (Jul. 18, 2013) (“*Order 784*”).
to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service; (iii) requires each public utility transmission provider to post and update yearly certain Area Control Error (“ACE”) data; and (iv) revises FERC accounting and reporting requirements to better account for and report transactions associated with the use of energy storage devices in public utility operations. The FERC found that the record in this proceeding was insufficient for it to relieve restrictions for Reactive Supply and Voltage Control service and Regulation and Frequency Response service in the same manner as Imbalance and Operating reserves, but indicated that it intends to gather further information regarding the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service in a separate, new proceeding. Order 784 will become effective November 27, 2013. Compliance filings implementing the changes to OATT Schedule 3 must be submitted on or before December 27, 2013. Requests for clarification of Order 784 were filed by EEI, Powerex, SoCal Edison, and WSPP. On September 16, 2013, the FERC issued a tolling order affording it additional time to consider the requests for clarification, which remain pending before the FERC.

- **Order 771: Availability of e-Tag Information to FERC Staff (RM11-12)**

  Rehearing of portions of Order 771 has been requested and remains pending. As previously reported, the FERC issued Order 771 on December 20, 2012. Order 771 granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags (“e-Tags”) used to schedule the transmission of electric power interchange transactions in wholesale markets. Order 771 requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, Order 771 requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. Order 771 became effective February 26, 2013. In response to requests for clarification and/or rehearing of Order 771 filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies (collectively, the “Rehearing Requests”), the FERC issued, on March 8, 2013, Order 771-A. Order 771-A addressed only those issues that needed to be answered on an expedited basis to allow affected entities to comply with the requirement to ensure FERC access in a timely manner to the e-Tags covered by Order 771. The FERC noted that it would issue an additional rehearing order, addressing the remaining issues raised on rehearing and clarification, which therefore remain pending before the FERC.

- **Order 764-A: Variable Energy Resources (RM10-11)**

  Requests for rehearing and/or clarification of Order 764-A remain pending before the FERC. As previously reported, the FERC, in Order 764-A, affirmed its basic Order 764 determinations.

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117 Order 771-A clarified that: (1) Balancing Authorities and their Authority Services will have until 60 days after publication of this order to implement the validation requirements of Order 771; (2) validation of e-Tags means that the Sink Balancing Authority, through its Authority Service, must reject any e-Tags that do not correctly include the FERC in the CC field; (3) the requirement for the FERC to be included in the CC field on the e-Tags applies only to e-Tags created on or after March 15, 2013; (4) the FERC will deem all e-tag information made available to the FERC pursuant to Order 771 as being submitted pursuant to a request for privileged and confidential treatment under 18 CFR 388.112; (5) the FERC is to be afforded access to the Intra-Balancing Authority e-Tags in the same manner as interchange e-Tags; and (6) the requirement on Balancing Authorities to ensure FERC access to e-Tags pertains to the Sink Balancing Authority and no other Balancing Authorities that may be listed on an e-Tag.
clarification, and granted EEI’s request to extend the period for compliance filings. Specifically, *Order 764-A* clarified (i) that the intra-hour scheduling reform adopted in the *Order 764* applies to *all* transmission customers that schedule transmission service under an OATT;\(^{119}\) (ii) in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges;\(^{120}\) and (iii) that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.\(^{121}\) Remaining requests for clarification and/or rehearing were denied. Requests for clarification and/or rehearing of *Order 764-A* were submitted on January 22, 2013 by Powerex and Iberdrola. On February 19, 2013, the FERC issued a tolling order affirming it additional time to consider the Powerex and Iberdrola requests, which remain pending before the FERC. The region’s *Order 764/764-A* compliance revisions were considered and supported at the August 2, 2013 meeting. Since the last report, the ISO, NEPOOL, PTO AC, CSC and SSPs jointly filed, on November 12, 2013, New England’s compliance changes (see Section IV, ER14-375 above). If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrange@daypitney.com).

- **NOPR: Incorporation of WEQ Version 003 Standards (RM05-5)**

  On July 18, the FERC issued a NOPR\(^{123}\) which proposes to amend FERC regulations by incorporating by reference *Version 003* of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant (“WEQ”) of the North American Energy Standards Board (“NAESB”). The Version 003 Standards update earlier versions of these standards previously incorporated by reference into FERC regulations at 18 CFR 38.2. The Version 003 standards include modifications to support Order Nos. 890, 890-A, 890-B and 890-C, including the standards to support Network Integration Transmission Service on an Open Access Same-Time Information System (“OASIS”), Service Across Multiple Transmission Systems (“SAMTS”), standards to support FERC policy regarding rollover rights for redirects on a firm basis, standards that incorporate the functionality for transmission providers to credit redirect requests with the capacity of the parent reservation and standards modifications to support consistency across the OASIS-related standards. The Version 003 Standards also include modifications to the OASIS-related standards that NAESB states support Order Nos. 676, 676-A, 676-E and 717 and add consistency. In addition, there are modifications to the Coordinate Interchange standards to compliment recent updates to e-Tag specifications, modifications to the Gas/Electric Coordination standards to provide consistency between the two markets, and re-organized and revised definitions to create a standard set of terms, definitions and acronyms applicable to all NAESB WEQ standards. The Version 003 Standards include the Standards addressed in *Order 676-G* below and the recent Smart Grid Standards. Comments on the WEQ Version 003 Standards NOPR were due on or before September 24, 2013,\(^{124}\) and were filed by 11 parties, including APPA, EEI, and the IRC. This matter is pending before the FERC.

- **Order 676-G: Incorporation of WEQ DR and EE M&V Standards (RM05-5)**

  On February 21, 2013, the FERC issued *Order 676-G*,\(^{125}\) which amends FERC regulations to incorporate by reference the business practice standards adopted by the NAESB Wholesale Electric Quadrant (“WEQ”) to

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\(^{119}\) *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246 (2012) (“*Order 764*”), order on reh’g, 141 FERC ¶ 61,232 (2012), reh’g requested.

\(^{120}\) *Id.* at P 15.

\(^{121}\) *Id.* at P 19.

\(^{122}\) *Id.* at P 23.


\(^{124}\) The *WEQ Version 003 Standards NOPR* was published in the *Fed. Reg.* on July 26, 2013 (Vol. 78, No. 144) pp. 45,096-45,104.

categorize various DR and energy efficiency (“EE”) products and services and to support the measurement and verification (“M&V”) of those products and services in RTO/ISOs (collectively, the “Phase II M&V Standards”). The standards provide common definitions and processes regarding DR and EE products in organized wholesale electric markets where such products are offered. The Phase II M&V Standards also require each RTO/ISO to address in its governing documents the performance evaluation methods to be used for DR products. The FERC stated that the Phase II M&V Standards facilitate the ability of DR and EE providers to participate in RTO/ISOs, “reducing transaction costs and providing an opportunity for more customers to participate in these programs, especially for customers that operate in more than one organized market”\(^\text{126}\) and “represent an incremental improvement to the existing standards that we incorporated by reference in Order No. 676-F.”\(^\text{127}\) Order 676-G became effective May 6, 2013.\(^\text{128}\) The PSEG Companies requested rehearing of Order 676-G on March 25, 2013. The FERC issued a tolling order on April 22, 2013 to allow it additional time to consider the PSEG Companies’ request, which remains pending before the FERC. With respect to implementation, compliance was required beginning May 6, 2013, and inclusion in the OATT required, either in a stand-alone filing or as part of an unrelated tariff filing, no later than December 31, 2013.\(^\text{129}\) New England’s Order 676-G compliance changes were filed on August 7, 2013 and accepted September 4, 2013.

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**XIII. Natural Gas Proceedings**

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jennifer Galiette (860-275-0338; jgaliette@daypitney.com).

- **Order 787: Gas/Electric Operational Info Sharing (RM13-17)**

  On November 15, the FERC issued its final rule revising its regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share nonpublic, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility’s or pipeline’s system.\(^\text{130}\) Recipients of the non-public, operational information will be subject to a No-Conduit Rule that prohibits subsequent disclosure of that information to an affiliate or third party. The approach to the sharing of non-public information proposed by the FERC is intentionally permissive, but the FERC noted that should this voluntary approach prove inadequate to promote reliable service or operational planning on natural gas pipelines and electric transmission systems, it may revisit the need to require certain communications or information sharing between transmission operators in the future. Order 787 will become effective December 23, 2013.\(^\text{131}\)

- **Natural Gas and Electric Market Coordination (AD12-12)**

  As previously reported, the FERC issued, on November 15, 2012, an order directing further conferences and reports in the gas-electric coordination initiative.\(^\text{132}\) Based on the issues raised during the regional technical

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\(^\text{126}\) *Id.* at P 1.

\(^\text{127}\) *Id.* at P 33.


\(^\text{129}\) The FERC will allow an RTO/ISO to incorporate the WEQ standard by reference in its OATT using the following language: “Measurement and Verification of Wholesale Electricity Efficiency (WEQ-021 2010 Annual Plan Item 4(d), July 16, 2012; and Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2010 Annual Plan Items 4(a) and 4(b), Mar. 21, 2011)”.


\(^\text{131}\) *Order 787* was published in the *Fed. Reg.* on Nov. 22, 2013 (Vol. 78, No. 226) pp. 70,164-70,188.

\(^\text{132}\) *Coordination Between Natural Gas and Elec. Markets*, 141 FERC ¶ 61,125 (2012) (“November 15 Order”). FERC Staff’s report detailing the discussions that took place at the five regional technical conferences during summer 2012, including the Aug 20, 2012 conference in Boston, is available on the FERC’s eLibrary.
conferences in August, the November 15 Order directed FERC staff to conduct two technical conferences: one focusing on ways to enhance communication between the two industries; and one focusing on how to design the most efficient scheduling systems for both industries. The November 15 Order also required each ISO and RTO to appear before the FERC on May 16, 2013 and October 17, 2013 to detail their efforts and progress in improving coordination between the industries, and to discuss any natural gas transportation concerns that arise during the winter heating season and any fuel-related generator outages during the winter and spring. Since the last report, each of the ISO/RTOs appeared before the FERC at its October 17 open meeting. RTO/ISO comments/presentations from the October 17 meeting are posted on eLibrary. Finally, to monitor the progress made by the two industries, the order directs FERC staff to report to the FERC on natural gas and electric coordination activities at least once each quarter in 2013 and 2014.

In accordance with the November 15 Order, FERC staff has held two technical conferences, one on February 13, 2013 to elicit input pertaining to information sharing and communications issues between the natural gas and electric power industries, and one on April 25, 2013 focused on natural gas and electric scheduling, and issues related to whether and how natural gas and electric industry schedules could be harmonized in order to achieve the most efficient scheduling systems for both industries. On May 16, the FERC convened, as planned, representatives from each RTO/ISO who shared experiences from the winter and spring and described progress towards refining existing practices to provide better coordination between the natural gas and electric industries and ensure adequate fuel supplies. Concerns with natural gas transportation that emerged during the winter heating season were addressed and fuel-related generator outages during the winter and spring were identified. Kevin Kirby presented “ISO New England Winter Operational Experiences and Regional Actions”, which, together with the materials of each of the other speakers, is posted in the FERC’s eLibrary. In follow-up to the May 16 presentation, the FERC, on June 6, requested that Mr. Kirby and each of the ISO/RTO presenters respond to a series of questions posed by no later than July 5, 2013. The questions to New England can be found at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13274467. Each of the ISO/RTOs submitted their responses, as requested, by the July 5 deadline. ISO-NE’s responses are available at http://www.iso-ne.com/regulatory/ferc/filings/2013/jul/ad12-12-000_7-5-13_response_to%20ferc_ltr.pdf.

- **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**
  
  Comments on the FERC’s November 15, 2012 NOI seeking input on what changes, if any, should be made to the regulations under the natural gas market transparency provisions of section 23 of the Natural Gas Act (“NGA”) are pending before the FERC. As previously reported, the FERC is considering the extent to which quarterly reporting of every jurisdictional natural gas transaction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency. Comments were received from over 40 parties.

- **Natural Gas-Related Enforcement Actions**
  
  The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. There was no activity since the last Report

### XIV. State Proceedings & Federal Legislative Proceedings

**No Activity to Report**

### XV. Federal Courts

The following are NEPOOL-related matters, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the United States Court of Appeals for the District of Columbia Circuit (unless otherwise noted). An “***” following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no
organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **New England’s Order 745 Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336

  Appellants: EPSA and NEPGA

  On July 16, 2012, EPSA and NEPGA filed a petition for review of FERC’s orders on New England’s Order 745 (Demand Response Compensation) filings. On August 16, 2012, EPSA and NEPGA filed a statement of issues as well as an unopposed motion to hold case in abeyance pending the final resolution of Case Nos. 11-1486, et al. (EPSA et al. v. FERC) (see Orders 745 and 745-A below). On August 23, 2012, the Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the course issuance of mandate in the Order 745 appeal.

- **Orders 1000 and 1000-A ((12-1232 consolidated with 12-1233, 12-1250, 12-1276, 12-1279, 12-1280, 12-1285, 12-1292, 12-1293, 12-1296, 12-1299, 12-1300, 12-1304, 12-1448, 12-1478, and 7th Cir. 12-2248)**
  Underlying FERC Proceedings: RM10-23

  Appellants: SC PSA, Coalition for Fair Transmission, PSEG, and Sacramento Municipal Utility District

  Petitions for review of FERC’s Order 1000 and 1000-A, as identified in previous reports, remain pending before the DC Circuit in the consolidated proceedings identified above. Petitioners briefs were filed on May 28, 2013; Respondent’s brief, September 25, 2013; Intervenors in Support of Respondent’s Brief, October 16; and Reply Briefs, November 15. Final Briefs are due on or before December 13, 2013. The date for oral arguments and the composition of the merits panel has not yet been ordered.

- **FCM Re-Design (12-1060 consolidated with 12-1074, 12-1085, and 12-1149) **
  Underlying FERC Proceedings: ER10-787; EL10-57; EL10-50

  Appellants: NEPGA, NSTAR, MMWEC/NHEC, VT DPS/VT PSB, NRG

  Petitions for review of FERC’s orders in the FCM Re-Design proceeding were filed by NEPGA on January 27, 2012; by NSTAR on February 3, 2012; by MMWEC/NHEC on February 10, 2012; by VT DPS/VT PSB on March 1, 2012; and by NRG on March 16, 2012. By orders dated February 7, 2012, February 27, 2012, March 2, and March 22, 2012, the Court consolidated the first four cases, with Case No. 12-1060 remaining the lead Case No. On February 29, 2012, the FERC filed an unopposed motion to hold the NEPGA, NSTAR, MMWEC/NHEC petitions in temporary abeyance pending expiration of the statutory deadline for the filing of petitions for review of the challenged orders. On May 7, 2012, NEPOOL notified the Court of its intent to be aligned as an intervenor in support of NSTAR (12-1074) and MMWEC/NHEC (12-1085), reserving the right to join in an intervenors’ brief in support of those petitioners. On October 9, briefs were filed by MMWEC/NHEC, NSTAR, and NEPGA. Supporting petitions were filed on October 23 by NECPUC and PSEG. NEPOOL indicated that it would not join in any intervenor’s brief. On January 7, 2013, FERC filed its Respondent Brief. Intervenor for Respondent Briefs were filed on January 22, 2013 by NEPGA and jointly by the CT PURA, HQ US, NICC, NSTAR, and NECPUC. Reply Briefs for Generator Petitioners and Distribution Utility Petitioners were filed on February 5, 2013. Final Briefs were submitted on March 5, 2013. Oral arguments were held on November 19, 2013 before Judges Sentelle, Brown and Griffith. This matter is now pending a decision of that panel.

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133  138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).
134  136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).
• Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)
  Underlying FERC Proceedings: RM10-17-000
  Appellants: EPSA, CAISO, ODEC, EEI, CA PUC

As previously reported, petitions for review of FERC’s Order 745 (Demand Response Compensation) were filed by EPSA on December 23, 2011; by CAISO on December 27, 2011; by Old Dominion Electric Cooperative (“ODEC”); and by EEI and the California Public Utilities Commission (“CA PUC”) on February 13, 2012. The DC Circuit consolidated the EPSA and CAISO cases on December 28. By orders dated February 13, 2012 and February 15, 2012, the Court consolidated Case Nos. 12-1088, 12-1091 and 12-1093 with 11-1486. All briefing has been completed. Oral argument in this case was held on September 23, 2013 and this matter is pending before the DC Circuit.


On September 30, the United States District Court for the District of Maryland found that a Maryland Public Service Commission (“MD PSC”) order directing three Maryland distribution utilities to enter into a ‘contract for differences’ for capacity and energy in the PJM control area (the “CfD”) with a gas-fired merchant generator selected by the MD PSC (the “MD PSC Order”) violated the Supremacy Clause of the United States Constitution and cannot be enforced.

The MD PSC Order, after finding that the long-term demand for electricity in Maryland, and specifically in the transmission-congested area encompassing portions of Maryland and the District of Columbia (“SWMAAC Zone”), compelled it to order new generation in that Zone by 2015, directed the utilities to negotiate and enter into the CfD with CPV Maryland, LLC (“CPV”), which had been selected by the MD PSC to provide that generation pursuant to a MD PSC-implemented competitive bid process (“RFP”). Under the CfD, CPV was guaranteed a fixed price for its capacity and energy sales in the PJM markets. The CfD required CPV be paid by the utilities for any revenue shortfall below the fixed contract price and that CPV pay the utilities any excess revenue above the fixed contract price. Any losses would be recouped from, and any gains passed onto, those utilities’ standard offer service customers. The MD PSC Order was challenged by a number of PPL companies, PSEG Power, and Essential Power (“Plaintiffs”) on the grounds that the Order violated the U.S. Constitution’s Supremacy Clause and “dormant” Commerce Clause, and that the MD PSC had deprived Plaintiffs of their federal statutory rights (“Section 1983 Claim”).

The District Court held that the MD PSC Order, through the CfD, set or established the ultimate price to be received by CPV for its wholesale energy and capacity sales. However, by setting that price, the MD PSC encroached on the FERC’s exclusive authority to set wholesale energy and capacity prices. The FERC, the District Court stated, “has exclusive domain in that field and has fixed the price for wholesale energy and capacity sales in the PJM Markets as the market-based rate produced by the auction processes approved by FERC and utilized by PJM.”

138 MD PSC Order No. 84815 (Apr. 12, 2012).
139 Id. at pp 29-30.
140 See id. at pp. 26-27.
141 The “dormant commerce clause” is a doctrine developed by the U.S. Supreme Court that limits states’ power to improperly discriminate against interstate commerce, even in the absence of affirmative federal law/regulation, or where federal law/regulation is “dormant”.
142 District Court Order at *132.
143 Id. at *133.
While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders, the scope of Maryland’s power is necessarily limited by FERC’s exclusive authority to set wholesale energy and capacity prices under, *inter alia*, the Supremacy Clause and the field preemption doctrine.144 Based on this principle, Maryland cannot secure the development of a new power plant by regulating in such a manner as to intrude into the federal field of wholesale electric energy and capacity price-setting.145

Accordingly, the MD PSC Order was found to have violated the Supremacy Clause by virtue of field preemption, and the PSC was enjoined from enforcing the Generation Order, which includes the requirement that the Maryland utilities enter into the CfD with CPV.146

With respect to Plaintiffs’ remaining claims (the dormant Commerce Clause and Section 1983 Claims), the Court denied both. The Court denied the dormant Commerce Clause claim finding that (i) the MD PSC Order did not affect the ability of other market participants to sell energy and capacity in the PJM Markets and (ii) the addition of a state-sponsored market participant physically located within the SWMAAC Zone did not impose a burden on interstate commerce.147 The Section 1983 Claim was not viable, the Court found, because “the Supremacy Clause is not a source of substantive individual rights that could support an action brought pursuant to Section 1983.”


On October 11, the United States District Court for the District of New Jersey issued an analogous decision declaring unconstitutional (and therefore null and void) New Jersey’s Long Term Capacity Agreement Pilot Program Act (“LCAPP”).148

LCAPP authorized, pursuant to New Jersey Public Service Board (“NJ PSB”) oversight, the construction of several gas-fired generators in or near New Jersey “[to] ensure[] sufficient generation is available to the region, and thus the users in [New Jersey] in a timely and orderly manner”149 and to address a perceived lack of incentives under PJM’s reliability pricing model (“RPM”) to achieve that goal. Like the MD PSC Order, to accomplish those goals, LCAPP required New Jersey’s four electric distribution companies to enter into NJ PSB-issued “standard offer capacity agreements” or “SOCAs” with NJ PSB-selected generators (“LCAPP generators”), obligating the LCAPP generators to construct their facilities and participate in the RPM. The utilities were obligated to pay for any RPM revenue shortfall below the LCAPP generator’s NJ PSB-approved development costs, while the LCAPP generators were obligated to pay back any excess RPM Auction revenues received above the generator’s NJ PSB-approved development costs.150 Any losses would be recouped from, and

144 “Field preemption” is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be implied when federal law/regulation “occupies the field” in which the state is attempting to act/regulate. Field preemption occurs when there is “no room” left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

145 *Id.* at *102.

146 The ability of the Maryland utilities and CPV to enter into the CfD absent state directive was not directly challenged by the Plaintiffs and was not addressed by the District Court Order.

147 The Court also held that, even if the Generation Order could be viewed as placing or imposing some burden on interstate commerce, the burden would be *de minimis*, and thus, not clearly excessive in relation to the benefits to Maryland.


149 N.J.S.A. § 48:3-98(d)(2).

150 *NJ Order* at *72-73.
any gains passed onto, those utilities’ standard offer service customers. LCAPP and its implementation was challenged by PPL, Atlantic City, Calpine, Exelon, and PSEG companies.

The Court found LCAPP and its implementation unconstitutional under both the field and conflict preemption doctrines of the Supremacy Clause.\textsuperscript{151} With respect to the field preemption doctrine, the Court stated “[a]lthough the State of New Jersey and the NJ PSB retained the responsibility for the siting and construction of power plants, they are required to exercise this responsibility without interfering with the [FERC]’s exclusive authority to regulate wholesale sales of electricity in interstate commerce.”\textsuperscript{152} By establishing the price that LCAPP generators would receive for their sales of capacity, LCAPP “supplants the Federal Power Act and intrudes upon the FERC’s exclusive jurisdiction over interstate wholesale power rates.”\textsuperscript{153} The Court rejected arguments that the SOCAs were purely financial contracts, and thereby did not intrude upon the FERC’s exclusive jurisdiction. “[T]he SOCAs are contingent upon the LCAPP generators’ successful sale of capacity to PJM” and “expressly condition payment on physical performance.”\textsuperscript{154} Accordingly, LCAPP “invades the field occupied by Congress and is [field] preempted by the Federal Power Act.”\textsuperscript{155} The Court also found that LCAPP and the SOCAs were unconstitutional under the conflict preemption doctrine of the Supremacy Clause.\textsuperscript{156} “From reviewing the entire scheme of the RPM process, it is clear that [LCAPP] [and the SOCA’s imposition of a government-imposed price] poses as an obstacle to the [FERC]’s implementation of the RPM.”\textsuperscript{157}

\begin{itemize}
\item \textsuperscript{151} The Court denied Plaintiffs’ dormant Commerce Clause claim that the “community benefit” points awarded to New Jersey generators unconstitutionally favored in-state enterprises over out-of-state enterprises (effectively prohibiting out-of-state generators from competing to be LCAPP-eligible generators), finding it reasonable that the NJ PSB would incentivize construction in areas where reliability concerns are in flux. \textit{Id.} at *110.
\item \textsuperscript{152} \textit{Id.} at *104.
\item \textsuperscript{153} \textit{Id.} at *103.
\item \textsuperscript{154} \textit{Id.} at *102. Physical performance includes plant construction, provision of available capacity, bidding into and clearing in RPM and the PJM markets.
\item \textsuperscript{155} \textit{Id.} at 103.
\item \textsuperscript{156} “Conflict preemption” occurs where there is a conflict between a state law and a federal law. (“[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute.”). Such a conflict occurs when “the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to ‘the entire scheme of the statute’ and determine ‘[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State’s acknowledged power, which interferes with or is contrary to federal law, must yield.” \textit{Id.} at 105-106.
\item \textsuperscript{157} \textit{Id.} at 106.
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