David T. Doot
Secretary

November 25, 2015

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of December 4, 2015 NEPOOL Participants Committee 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 4, 2015 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**. Larry Gasteiger, Chief of Staff to FERC Chairman Norman Bay, is joining us at the beginning of the meeting. We also may be joined at breakfast by FERC Commissioner Cheryl LaFleur. We hope you all plan to arrive early and have a chance over breakfast to interact informally with our federal regulators. 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://nepool.com/NPC_2015.php. For your information, this meeting is recorded, as are all the Participants Committee meetings.

By way of reminder, the December meeting is the Participants Committee's annual meeting and, if any member wishes to change Sectors for next year, you must provide us with written notice of that request prior to the December 4 meeting. Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first annual meeting following that request, so if you miss this deadline, your next chance will not be until the December 2016 meeting.

Directions to the Colonnade Hotel are included with this notice. The cut-off date for making reservations in the NEPOOL block at the Colonnade Hotel has passed. If you have not made a reservation, we would suggest you contact the Colonnade directly (617-424-7000) to see if they have any rooms available and reference the "NEPOOL Participants Committee" block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the November 6, 2015 meeting. Preliminary minutes for the November 6 meeting, marked to show changes from the draft circulated with the initial notice, are included with this notice and posted at http://nepool.com/NPC_2015.php.

2. To adopt and approve all 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 Reliability Committee-recommended revisions to Section I.2.2 and III.G of the ISO Tariff and ISO Operating Procedure No. 3 - Transmission Outage Scheduling, to remove the Major Transmission Outages concept, to revise long-term economic evaluation and assessment timelines, and to make other clarifying and ministerial changes. Background material and a draft resolution are included with this supplemental notice.

3. To receive comments from Larry Gasteiger, Chief of Staff to Chairman Norman Bay 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 2015 NEPOOL Annual Report, which will be distributed at the Participants Committee meeting and posted with the meeting materials.

7. To elect NEPOOL Participants Committee Officers for 2016. A draft resolution reflecting the outcome of earlier balloting for the Participants Committee Chair and candidates for Secretary and Assistant Secretary is included with this supplemental notice.

8. To adopt a NEPOOL Budget for 2016. Background materials and a draft resolution are included with this supplemental notice.

9. To consider, and taken action as appropriate, on the following proposed changes to implement an alternative treatment of resource retirement requests:

   (a) Proposed revisions to Market Rule 1, Appendix A and Section I.2.2 (Definitions), as recommended by the ISO;

   (b) Proposed revisions to Sections III.12.4 and III.12.7.2, as recommended by the Reliability Committee; and

   (c) Proposed revisions to Section I.3.9.3 and Attachment K of Section II of the Tariff, as recommended by the ISO.

   Background materials which include draft resolutions are included with this supplemental notice.

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

11. To receive reports from committees and subcommittees.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Friday, November 6, 2015 at the Hilton Logan Airport Hotel, Boston, MA, pursuant to notice duly given. The meeting was preceded by meetings among modified Sector groups with the ISO Board, New England state officials, and FERC representatives. 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. Joel Gordon, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Gordon welcomed the members, alternates and guests who were present, including the ISO Board members, New England state officials, and FERC representatives in attendance following their earlier participation in the modified Sector discussions.

Before turning to the agenda for the meeting, Mr. Gordon noted that the process for selecting a Participants Committee Chair for 2016 was underway and he was interested in serving an additional year as the Chair, which would be a third term. He explained that his decision to run for election was a break from the custom of two-year terms for the Chair position. Mr. Doot referred the Committee to the memorandum and ballot circulated earlier that outlined the election and the voting process and, per past practice, only included the biographies of candidates for Chair. The governing documents provide for one-year terms for officers, but the custom had been for Chairs to step aside following service for two full one-year terms. Mr. Doot reported that there had been a prior example where a Chair served more than two years, and involved Mr. Richard Chapman, who served during the transition from the

prior Executive Committee to the Participants Committee. Mr. Doot encouraged Participants to submit their ballots, and indicated that if anyone changed their vote following this discussion, only the later ballot would be considered. Mr. Doot clarified in response to a question that there was no governing document that limited a Chair's service to two consecutive one-year terms.

APPROVAL OF OCTOBER 2, 2015 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the October 2, 2015 meeting as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the October 2 meetings were unanimously approved.

CONSENT AGENDA

Mr. Gordon 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 unanimously.

ORDER 1000 TARIFF COMPLIANCE REVISIONS

Mr. Jose Rotger, Transmission Committee Vice-Chair, referred the Committee to the materials circulated in advance of the meeting regarding revisions to Sections I and II of the ISO Transmission, Markets and Services Tariff (ISO Tariff) and the Transmission Operating Agreement (TOA) that were filed by the ISO and the Participating Transmission Owners (PTOs) in response to the October 2, 2015 FERC Order on Rehearing and Clarification and Compliance (October 2 Order). He reported that the Transmission Committee, at its October 27, 2015 meeting, considered and voted to recommend Participants Committee support for the

changes. He stated this matter would have been on the Consent Agenda but for the timing of the Transmission Committee's action. He reported that the ISO and PTOs made their compliance filing on November 2, before ~~the~~a Participants Committee vote, in order to meet the FERC's compliance deadline and that NEPOOL would file comments in response to that filing reflecting the action of the Participants Committee.

The Committee considered and approved unanimously the following motion:

> RESOLVED, that the Participants Committee supports the changes to the TOA and Sections I and II of the ISO-NE Tariff proposed in response to the FERC's Order No. 1000 October 2, 2015 Order, as recommended by the Transmission Committee and as reflected in the materials distributed to the Participants Committee for its November 6, 2015 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.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer, referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the October 2 meeting, which had been circulated and posted in advance of the meeting. He noted that the summary of the ISO Board Markets Committee reported that the ISO would be issuing a Request for Proposal (RFP) for ~~the~~ external market monitoring services. He said that the ISO would circulate that RFP to the Participants on November 9 and post the RFP on the ISO website.

ISO COO REPORT

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 on report highlights, which he explained reflected data through October 27 (October 25 for Real-Time Net Commitment Period Compensation (NCPC)), he reported for October that: (i) Energy Market value was $217 million over the period, down $73 million from September 2015 and down $17 million from October 2014; (ii) natural gas prices were 19.4% higher than September 2015 average values; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 11.3% lower than September 2015 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 100.1% in October, up from 98.6% in September (which he noted was the first time he saw more than 100% clearing day-ahead); (v) daily ~~Net Commitment Period Compensation (~~NCPC~~)~~ for October totaled $8 million, down $9.5 million from September 2015 NCPC; (vi) first contingency payments, totaling $3.8 million, were $1.8 million lower than September's; (vii) second contingency payments totaled $4 million, which was down $7.9 million from September 2015. The voltage support payments totaled $204,000, up $178,000 from September 2015. ~~The~~ NCPC payments were 2.5% of the total Energy market value.

Responding to questions, Dr. Chadalavada ~~stated the~~explained that uplift ~~of~~experienced on October 26 was caused by negative pricing (at almost -$150) during several overnight hours and the resulting payments were needed to make units whole in both the Day-Ahead and Real-Time Energy Market. He stated market changes, planned for February 2016 implementation, should reduce such uplift payments in the future. Regarding the reallocation of second contingency costs for September, he reported that $5.6 million of a total of $11.5 million in uplift would be reallocated to Network Load and split between ~~NSTAR/~~Eversource

(NSTAR) and National Grid. He stated that adjustment should be reflected on November billing statements.

He reported that the ISO Board approved the 2015 Regional System Plan (RSP15) at its November 5 meeting, that 2015 economic planning studies were underway, with all three study requests focused on the impacts of wind integration, that changes to the RSP process were being proposed to provide for the next RSP to be issued in 2017, and that all resource qualification information and associated Installed Capacity Requirements (ICR) and Local Sourcing Requirements for the tenth Forward Capacity Action (FCA10) would be filed with the FERC by November 10, 2015, with FCA10 scheduled to begin on February 6, 2016. He reported that the non-price retirement window closed on October 12 and that 728 MW of retirements were received, including a 677 MW full retirement request from Pilgrim. He expected the results of the reliability review to be shared with the Reliability Committee at its December meeting.

Dr. Chadalavada then provided an update on the 2015/16 Winter Reliability Program:

- Oil Program: 81 units submitted intent to provide 4.464 million barrels of inventory for the winter. Based on assets participating in the ~~p~~Program, the anticipated total oil investing potentially eligible for Winter Program payments ~~is~~was 2.965 million barrels, with an anticipated total cost exposure of $38.25 million (@$12.90/barrel).
- LNG Program: 8 units submitted intent to provide at least 1.42 million MMBTU of potential inventory. Based on asset submissions, capping submissions to permissible asset thresholds, total eligible LNG investing potentially eligible for Winter Program payments of $1.278 million MMBTU, with the anticipated total LNG program cost exposure of $2.75 million (@$2.15/MMBTU).
- DR Program: 6 assets accepted by the ISO submitted intent to provide at least 26.5 MW of interruption capability, with the anticipated total DR cost exposure of $132,000.

He noted that the ISO would provide monthly reports in December, January and February in addition to an end of season report on how the program worked for those winter months.

FAP CHANGES TO ESTIMATION OF HOURLY CHARGES

Mr. Kenneth Del Orto, Budget & Finance Subcommittee Chair, referred the Committee to and summarized the materials circulated in advance of the meeting regarding changes to the ISO Financial Assurance Policy (FAP) to modify how Market Participant's unsettled obligations would be estimated for purposes of determining their financial assurance requirements. He said that the Budget & Finance Subcommittee, at its October 9 teleconference, discussed and recommended, with no objection, Participants Committee support for the changes to the FAP.

The Committee then considered and approved unanimously the following motion:

> RESOLVED, that the Participants Committee supports the changes to the ISO Financial Assurance Policy relating to the estimation of Hourly Charges, 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 & Finance Subcommittee may approve.

ISO OP-14 CHANGES

Mr. Robert Stein, Reliability Committee Vice-Chair, referred the Committee to the revisions to ISO Operating Procedure No. 14 (OP-14) that were recommended for approval by the Reliability Committee. He reminded members that the Participants Committee considered and deferred voting on an initial set of OP-14 revisions at its September 2015 meeting and sent the matter back to the Reliability Committee for further consideration. That consideration resulted in a second set of revisions that was also recommended by the Reliability Committee.

He said that both sets of Reliability Committee-recommended changes (OP-14 Revisions) were being presented for a single vote.

He then summarized the ~~proposed changes~~OP-14 Revisions, explaining that two conceptual concerns had been raised with the ~~OP-14 R~~revisions as originally presented. The first was that the Revisions could result in very small and unaffiliated distributed generation projects being exposed needlessly to additional costs and requirements. He noted that many of the developers and owners of such projects were not represented by Committee members, and the Alternative Resources Sector through its Vice-Chair sought to minimize that impact while still satisfying the ISO's stated needs of visibility into the operations of certain small distributed generation. Second, some members questioned whether the changes should be part of the filed rate instead of only Operating Procedure revisions.

With the benefit of time after the Participants Committee deferral of the vote at its September meeting, interested Participants, state representatives and the ISO worked to resolve those concerns. The ISO agreed to add language that gave it flexibility to waive the aggregation rule if the type of scenario described occurred and ~~ISO-NE~~the ISO did not require the additional information. Also, clarifying changes were made to the OP-14 Revisions. The Reliability Committee voted on this second set of revisions at its October 21, 2015 meeting and recommended Participants Committee support.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the proposed OP-14 Revisions, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 6, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The AR Sector Vice-Chair expressed appreciation for the deferral, dialogue, and the accommodations reflected in the changes, but explained that there remained concerns with the proposed Revisions. He commended the ISO for committing to work with distributed generation resources and others affected by the rules in the future to address those continuing concerns. He said, therefore, that he and others would not oppose, but would abstain on, the motion to support the Revisions. Echoing that appreciation, members of the Generation and Supplier Sectors also suggested that there remained opportunities to refine and improve upon the Revisions, and indicated that they also would abstain. Representatives of the Publicly Owned Entities explained their concerns, as expressed during Technical Committee consideration of the changes, that these changes could impose additional cost and responsibilities for, and in the end would discourage the development of new, small distributed generation projects. Another added that the revisions were to material terms and conditions ~~that~~and belonged in the filed rate. For these reasons, the Publicly Owned Entities would oppose the changes.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the proposed OP-14 Revisions, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 6, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The Committee considered and approved the motion, with oppositions noted by CMEEC, Littleton NH, MMWEC and each of the Publicly Owned Entities that it represented, NHEC, VEC, VPPSA, and abstentions noted by BP, CLEAResult, ConEdison, CT OCC,

CPV, EnerNOC, Harvard, Marble River, ME OPA, Harvard, NGrid, NextEra, NRG, PowerOptions, Small LR Group Member, SunEdison (First Wind), TEC, UCS, and VEIC.

ARA HQICC AND ICR VALUES – 2016/17 ARA3, 2017/18 ARA2, AND 2018/19 ARA1 CAPACITY COMMITMENT PERIODS

Mr. Stein referred the Committee to the materials circulated in advance of the meeting regarding the megawatt (MW) values for the Hydro-Quebec Interconnection Capability Credit (ARA HQICC Values) and Installed Capacity Requirement (ARA ICR Values) to be used for the 2016/2017 3rd Annual Reconfiguration Auction (ARA), 2017/2018 2nd ARA, and 2018/2019 1st ARA. He reported that the ARA HQICC Values and ARA ICR Values for each of the three ARAs were proposed by the ISO and recommended for Participants Committee support by the Reliability Committee at its October 21 meeting.

Turning to the ARA HQICC Values, Mr. Stein stated that Participants had many of the same concerns that had been raised the prior month with respect to the FCA10 HQICC Values, which related to the calculation of tie benefits and the treatment of the Cross Sound Cable. The following motion respect to the HQICC Values was then duly made, seconded and approved with oppositions noted by CSC and LIPA, and an abstention noted by Emera Energy Services Subsidiaries:

> RESOLVED, that the Participants Committee supports the proposed ARA-related HQICC Values, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 6, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

Similarly, with respect to the ARA ICR Values, Mr. Stein stated that Participant concerns raised the prior month with respect to the FCA10 ICR Values, particularly the impact of distributed generation and demand response on the load forecast methodology, had also been raised in connection with the ARA ICR Values. A number of members reiterated additional concerns included (i) that the ARA ICR Values were viewed as too low as a result of perceived inappropriate treatment of renewable resources; (ii) the view of a contradiction between the premise for the Renewable Technology Resource Exemption, which was based on an expected average amount of peak load growth which would offset permitted out-of-market new entry, and the reality that treating behind-the-meter renewables as load reducers would further reduce peak demand to yield flat or declining peak demand; (iii) the impact on the long-term load forecast of planned behind-the-meter generators, which was different than how behind-the-meter resources had affected the long-term load forecast and ICR calculations in the past; (iv) objections to presuming certain performance of resources that do not exist and are not subject to pay-for-performance rigor; (v) impacts on the calculation of net CONE and the definition of a sloped demand curve, which if they resulted in improperly reduced clearing prices, could in the long-run result in price retirements and reliability challenges.

Then, the following motion with respect to the ICR Values was duly made and seconded:

> RESOLVED, that the Participants Committee supports the proposed ARA-related ICR Values, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its November 6, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The Committee approved the motion with a 80.97% Vote in favor (Generation Sector - 6.4%; Transmission Sector - 17.13%; Supplier Sector - 10.70%; Alternative Resources Sector - 14.38%; Publicly Owned Entity Sector - 17.15%; and End User Sector - 15.21%). (See Vote 1 on Attachment 2).

NEPOOL COMMENTS ON FERC CONNECTED ENTITY DATA COLLECTION NOPR

Mr. Michael Henry, Connected Entity Working Group Chair, referred the Committee to materials circulated in advance of the meeting regarding an outline of NEPOOL's comments in response to the September 17, 2015 FERC Notice of Proposed Rulemaking (NOPR) proposing regulations requiring the collection and reporting of "Connected Entity" data (Docket No. RM15-23). He stated the outline would serve as the guiding framework for NEPOOL's comments to the FERC, which were then due on or before November 30. He explained that the Participants Committee was being asked to consider the positions reflected in the outline and to direct NEPOOL Counsel to reflect those positions in comments to be filed with the FERC in response to the NOPR. The Working Group also recommended that the Participants Committee support the request for a technical conference submitted by a group of industry participants on October 29. He reported that NEPOOL Counsel would work with the him and the NEPOOL Officers on the final draft, to confirm it is consistent with the comments supported by the Participants Committee. He stated a near final draft would also be shared with the more than 30 members of the Working Group as well as to any Participant requesting to review the draft.

The Committee considered and approved unanimously the following motion:

> RESOLVED, that the NEPOOL Participants Committee (i) supports positions reflected in the comment outline as

recommended by the Connected Entity Working Group and as circulated to the Committee in advance of the November 6, 2015 meeting (the Outline), and (ii) authorizes and directs NEPOOL Counsel to reflect those positions in comments filed with the FERC in response to the NOPR.

LITIGATION REPORT

Mr. Doot referred the Committee to the November 5 Litigation Report that had been circulated and posted in advance of the meeting and encouraged anyone with comments or questions on the Report to contact NEPOOL Counsel.

COMMITTEE REPORTS

Mr. Rotger reported that the Transmission Committee was scheduled to meet on November 12 to review the interconnection process and reforms~~ at its November 12 meeting~~, noting that the ISO had deferred a vote on the changes to the December Transmission Committee meeting. Mr. Stacy Dimou reviewed that the Markets Committee was scheduled to meet on November 9-10 to review resource retirements. Mr. Dell Orto reported that the Budget & Finance Subcommittee was scheduled to meet on November 19 by teleconference to review the 2016 NEPOOL Budget. He also reported that an ad hoc group would be convened later in the year to discuss and recommend how to address certain disputes relating to the Generation Information System given the termination of the NEPOOL Review Board Arrangements on January 1, 2016.

OTHER BUSINESS

Mr. Doot reminded the Committee of the annual meeting to be held December 4, 2015 in Boston at The Colonnade Hotel. He announced a December 3 Consumer Liaison Group

meeting, also to be held at The Colonnade Hotel. He urged members to submit their ballots for 2016 Chair.

Mr. Gordon requested that the Committee provide feedback to their Sector Vice-Chairs on the meetings held earlier in the day with the ISO Board, New England state officials, and FERC representatives, in order to inform discussions of how to improve those meetings in the future.

There being no further business, the meeting adjourned at 3:25 p.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
NOVEMBER 6, 2015 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned			Chung Liu
Belmont Municipal Light Department	Publicly Owned		Phil Smith	
Boylston Municipal Light Department	Publicly Owned			Chung Liu
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Company	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	John Flumerfelt	Brett Kruse	
Central Maine Power Company	Transmission	Eric Stinneford		
Chester Municipal Electric Light Department	Publicly Owned	Phil Smith		
Chicopee Municipal Lighting Plant	Publicly Owned			Chung Liu
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Concord Municipal Light Plant	Publicly Owned		Phil Smith	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		David Mullett
Connecticut Office of Consumer Counsel	End User		Joe Rosenthal	
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Daniel Pierpont		
Cross-Sound Cable Company (CSC)	Supplier	Brian Reinhart (tel)		
Danvers Electric Division	Publicly Owned		Phil Smith	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Dominion Energy Marketing, Inc.	Generation	Jim Davis		Tom Kaslow
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Maine	Transmission	Jeff Jones	Jose Rotger	Stacy Dimou Mike Henry Andrew McCullough Sandi Hennequin
Energy America, LLC	Supplier	Ron Carrier		Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, LLC	Generation	Mark Potkin	Ken Dell Orto	
Essential Power, LLC	Generation	M.Q. Riding	Bill Fowler	
Eversource Energy	Transmission	James Daly	Joe Staszowski	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
Fairchild Seminconductor Corporation	End User	Gus Fromuth		
Food City, Inc.	End User	Gus Fromuth		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Garland Manufacturing Company	End User	Gus Fromuth		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Phil Smith	
Granite Ridge/Merrill Lynch	Supplier		Bill Fowler	
Groton Electric Light Department	Publicly Owned			Chung Liu
Groveland Electric Light Department	Publicly Owned		Phil Smith	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Abby Krich
Hammond Lumber Company	End User	Gus Fromuth		
Harvard Dedicated Energy Limited	End User	Mary Smith		Paul Peterson
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Phil Smith	
Holden Municipal Light Department	Publicly Owned			Chung Liu
Hull Municipal Lighting Plant	Publicly Owned			Chung Liu
Industrial Energy Consumer Group	End User	Don Sipe		
Ipswich Municipal Light Department	Publicly Owned			Chung Liu
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Littleton (MA) Electric Light & Water Department	Publicly Owned		Phil Smith	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	David Mullett
Maine Public Advocate Office (ME OPA)	End User	Agnes Gormley		Paul Peterson
Maine Skiing, Inc.	End User	Don Sipe		

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ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
NOVEMBER 6, 2015 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Mansfield Municipal Electric Department	Publicly Owned			Chung Liu
Marblehead Municipal Light Department	Publicly Owned			Chung Liu
Marble River, LLC	Supplier			Steve Garwood
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Development Finance Agency	Publicly Owned		Phil Smith	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned		Chung Liu	
Merrimac Municipal Light Department	Publicly Owned		Phil Smith	
Middleborough Gas and Electric Department	Publicly Owned			Chung Liu
Middleton Municipal Electric Department	Publicly Owned		Phil Smith	
National Grid	Transmission	Timothy Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski		Brian Forshaw David Mullett
New Hampshire Industries	End User	Gus Fromuth		
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing LLC	Generation	Dave Cavanaugh		Bob Stein
Parkview Adventist Medical Center	End User	Gus Fromuth		
Pascoag Utility District	Publicly Owned		Phil Smith	
Paxton Municipal Light Department	Publicly Owned			Chung Liu
Peabody Municipal Light Plant	Publicly Owned			Chung Liu
PowerOptions, Inc.	End User	Cindy Arcate		Paul Peterson
Princeton Municipal Light Department	Publicly Owned			Chung Liu
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon	Robert Messmer	
Reading Municipal Light Department	Publicly Owned		Jane Parenteau	
Repsol Energy North America Company	Supplier		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Phil Smith	
Russell Municipal Light Dept	Publicly Owned			Chung Liu
St. Anselm College	End User	Gus Fromuth		
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned			Chung Liu
Small Load Response Group Member	AR	Doug Hurley	Brad Swalwell (tel)	
Small Renewable Generation Group	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned			Chung Liu
Sterling Municipal Electric Light Department	Publicly Owned			Chung Liu
Stowe Electric Department	Publicly Owned		Phil Smith	
SunEdison (First Wind Energy Marketing, Inc.)	AR	John Keene		Bob Stein Abby Krich (tel)
Taunton Municipal Light Department	Publicly Owned		Phil Smith	
Templeton Municipal Lighting Plant	Publicly Owned			Chung Liu
The Energy Consortium	End User		Mary Smith	Paul Peterson
The Westerly Hospital	End User		Gus Fromuth	
TransCanada Power Marketing Ltd.	Generation	Dan Congel		
Union Leader	End User		Gus Fromuth	
Union of Concerned Scientists	End User		Francis Pullaro	
United Illuminating Company (UI)	Transmission		Alan Trotta	
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		David Mullett
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Wakefield Municipal Gas and Light Department	Publicly Owned			Chung Liu
Wallingford DPU Electric Division	Publicly Owned	Phil Smith		
Wellesley Municipal Light Plant	Publicly Owned		Phil Smith	
West Boylston Municipal Lighting Plant	Publicly Owned			Chung Liu
Westfield Gas & Electric Light Department	Publicly Owned		Phil Smith	

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ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
NOVEMBER 6, 2015 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Z-TECH, LLC	End User		Gus Fromuth	

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ROLL CALL VOTE TAKEN AT
NOVEMBER 6, 2015 PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR/GROUP	VOTE
GENERATION	6.40
TRANSMISSION	17.13
SUPPLIER	10.70
ALTERNATIVE RESOURCES	14.38
PUBLICLY OWNED ENTITY	17.15
END USER	15.21
% IN FAVOR	**80.97**

GENERATION SECTOR

Participant Name	VOTE
CPV Towantic, LLC	F
Dominion Energy Marketing, Inc.	O
Entergy Nuclear Power Marketing LLC	F
Essential Power, LLC	O
GDF SUEZ Energy Marketing NA, Inc.	O
Generation Group Member	F
NextEra Energy Resources, LLC	O
NRG Power Marketing, LLC	O
IN FAVOR (F)	3
OPPOSED (O)	5
TOTAL VOTES	8
ABSTENTIONS (A)	0

TRANSMISSION SECTOR

Participant Name	VOTE
Emera	S
Emera Maine	F
Emera Energy Services Subsidiaries	A
Eversource Energy	F
National Grid	F
The United Illuminating Company	F
Vermont Electric Power Company, Inc.	F
IN FAVOR (F)	4.5
OPPOSED (O)	0
TOTAL VOTES	4.5
ABSTENTIONS (A)	0.5

ALTERNATIVE RESOURCES SECTOR

Participant Name	VOTE
Renewable Generation Sub-Sector	
Small RG Group Member	F
SunEdison (First Wind)	A
Distributed Generation Sub-Sector	
CLEAResult Consulting, Inc.	F
Load Response Sub-Sector	
EnerNOC, Inc.	F
Vermont Energy Investment Corp.	F
Small LR Group Member *Tangent Energy Solutions, Inc.*	F
IN FAVOR (F)	5
OPPOSED (O)	0
TOTAL VOTES	5
ABSTENTIONS (A)	1

SUPPLIER SECTOR

Participant Name	VOTE
BP Energy Company	A
Calpine Energy Services	A
Consolidated Edison Energy, Inc.	A
Cross-Sound Cable Company	O
DTE Energy Trading, Inc.	F
Dynegy Marketing and Trade, LLC	O
Energy America, LLC	F
Exelon Generation Company	A
Galt Power, Inc.	F
Granite Ridge/Merrill Lynch Commod.	A
H.Q. Energy Services (U.S.) Inc.	F
LIPA	O
Marble River, LLC	F
PSEG Energy Resources & Trade LLC	A
Repsol Energy North America	A
IN FAVOR (F)	5
OPPOSED (O)	3
TOTAL VOTES	8
ABSTENTIONS (A)	7

ATTACHMENT 2

ROLL CALL VOTE TAKEN AT
NOVEMBER 6, 2015 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	VOTE
Connecticut Office of Consumer Counsel	F
Harvard Dedicated Energy Limited	F
High Liner Foods (USA) Inc.	O
Maine Public Advocate Office	F
Mass. Attorney General's Office	F
PowerOptions, Inc.	F
The Energy Consortium	F
Union of Concerned Scientists	F
Utility Services Inc.	F
IN FAVOR (F)	8
OPPOSED (O)	1
TOTAL VOTES	9
ABSTENTIONS (A)	0

PUBLICLY OWNED ENTITY SECTOR

Participant Name	VOTE
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Department	F
Boylston Municipal Light Department	F
Chester Municipal Light Department	F
Chicopee Municipal Lighting Plant	F
Concord Municipal Light Plant	F
Conn. Municipal Electric Energy Coop.	F
Danvers Electric Division	F
Georgetown Municipal Light Dep't	F
Groton Electric Light Department	F
Groveland Electric Light Department	F
Hingham Municipal Lighting Plant	F
Holden Municipal Light Department	F
Holyoke Gas & Electric Department	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Department	F
Littleton (MA) Electric Light Dep't	F
Littleton (NH) Water & Light Dep't	F
Mansfield Municipal Electric Dep't	F
Marblehead Municipal Light Dep't	F
Mass. Development Finance Agency	F
Mass. Municipal Wholesale Electric Co.	F
Merrimac Municipal Light Dep't	F
Middleborough Gas and Electric Dep't	F
Middleton Municipal Electric Dep't	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	VOTE
New Hampshire Electric Coop.	F
Pascoag Utility District	F
Paxton Municipal Light Department	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Department	F
Rowley Municipal Lighting Plant	F
Russell Municipal Light Department	F
Shrewsbury's Electric & Cable Ops.	F
South Hadley Electric Light Dep't	F
Sterling Municipal Electric Light Dep't	F
Stowe (VT) Electric Department	F
Taunton Municipal Lighting Plant	F
Templeton Municipal Lighting Plant	F
Vermont Electric Cooperative	F
Vermont Public Power Supply Authority	F
Wakefield Municipal Gas & Light Dep't	F
Wallingford, Town of	F
Wellesley Municipal Light Plant	F
West Boylston Municipal Lighting Plant	F
Westfield Gas & Electric Light Dep't	F
IN FAVOR (F)	45
OPPOSED (O)	0
TOTAL VOTES	45
ABSTENTIONS (A)	0

CONSENT AGENDA

From the notice of actions of the November 18, 2015 ***Markets Committee***[1] meeting, dated November 18, 2015, which has been previously circulated:

1. **Revisions to MR1 (CTS Winter Reliability Program Cost Allocation)**

   Support revisions to Market Rule 1 (MR1) to appropriately address the Winter Reliability Program cost allocation consistent with Coordinated Transaction Scheduling (CTS) design, as recommended by the Markets Committee at its November 18, 2015 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 five abstentions noted (Generation Sector - 1, Supplier Sector – 2, AR Sector - 1, and End User Sector - 1).

From the notice of actions of the November 9-10, 2015 ***Markets Committee*** meeting, dated November 11, 2015, which has been previously circulated:

2. **Revisions to MR1 and Tariff (Modifications to FRM Offer Cap)**

   Support revisions to Market Rule 1 (MR1) and Tariff Section I.2.2 to set the FRM Offer Cap at $9/kW-month and eliminate the need to net the FCA price from the FRM price for a Forward Reserve Resource, as recommended by the Markets Committee and at its November 9-10, 2015 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.

3. **Revisions to MR1, MR1 Appendix F, Tariff, and Manuals M-11 and M-35 (DARD Pump Intertemporal Parameters)**

   Support revisions to Market Rule 1 (MR1), MR1 Appendix F, Tariff Section I.2.2, and Manuals M-11 (Market Operations) and M-35 (Definitions and Abbreviations) to add intertemporal parameters for DARD pumps and apply the Day-Ahead Energy Market NCPC Credit calculation to Fast Start and Flexible DNE Dispatchable Generators, as recommended by the Markets Committee at its November 9-10, 2015 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 one abstention noted in the Supplier Sector.

[1] Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/markets/markets-committee.

CONSENT AGENDA (cont.)

4. Conforming Revisions to Manuals M-11, M-20 and M-28 and OP-9 (CTS and Associated Clean-Up Changes)

Support revisions to conform Manuals M-11 (Market Operations), M-20 (Forward Capacity Market) and M-28 (Market Rule 1 Accounting) and Operating Procedure No. 9 (Scheduling and Dispatch of External Transactions) to Market Rule 1 language implementing CTS and associated clean-up changes, as recommended by the Markets Committee at its November 9-10, 2015 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 one abstention noted in the Supplier Sector.

5. Revisions to MR1 (De-List Bid Information Release Change)

Support revisions to Market Rule 1 (MR1) to reflect the FERC supported de-list bid price redactions, as recommended by the Markets Committee at its November 9-10, 2015 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 (Generation Sector - 3, Transmission Sector - 1, and Supplier Sector - 3).

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: November 25, 2015

RE: Transmission Outage Scheduling Revisions

At the December 4, 2015, meeting of the Participants Committee you will be asked to vote on revisions related to transmission outage scheduling that were unanimously recommended for approval by the Reliability Committee. The revisions include changes to Section I of the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff, Appendix G to Market Rule I, and Operating Procedure 3 (collectively, the "Transmission Outage Scheduling Revisions"), which have been included with this memo. The revisions remove the major transmission outage category from the documents as no longer necessary. An ISO NE presentation on the revisions has also been included with this memo.

The Reliability Committee considered the proposed revisions and, at its November 20, 2015 meeting, voted unanimously to recommend Participants Committee support for the revisions. This item would have been on the Consent Agenda but for the timing of the votes.

The following resolution could be used for Participants Committee consideration of this matter:

> RESOLVED, that the Participants Committee supports the proposed Transmission Outage Scheduling Revisions, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its December 4, 2015 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

ISO Tariff, Market Rule 1 – Appendix G, Operating Procedure 3 Changes

Major Transmission Outage (MTO), Long-Term Economic Analysis and Assessment, Define "Recall Time"

Jerry Elliott

Michael Courchesne

Tariff, Market Rule #1 and OP-3 Updates

- Remove Major Transmission Outage (MTO) category
- Changes to Long-Term economic evaluation
- Relax Long-Term assessment timelines
- Clarify “Recall Time” definition

MTO

- Remove MTO references
  - ISO Tariff: Section I – General Terms and Conditions
  - Market Rule 1 – Appendix G
  - OP-3
- Long-Term outage coordination process has matured:
  - Transmission equipment outages submitted (> 21 days in advance) increased from **10.3%** in 2005 to **80%** in 2014
  - Transmission equipment outages submitted > 90 days in advance from **23%** in 2010 to **54%** in 2014
- Posting of current and historical transmission outages selected in Monthly Market auctions are available through the ISO-NE eFTR interface
- MTO category is no longer necessary as the process considers all approved outages for the FTR model

OP-3 – Long-Term Economic Evaluation

- Remove Long-Term economic analysis requirement for all outages submitted > 90 days in advance
  - Market Rule #1 – Appendix G
  - OP-3
- Not all Major Transmission Element (MTE) outages necessitate a Long Term economic evaluation
  - Not every Long-Term outage submitted greater than 90 days removes equipment from service
  - Some Long-Term outages are coordinated to reduce the economic impact on the system as well as local generation
  - Instances when outages are purposefully coordinated to mitigate generation must run requirements

OP-3 – LT Assessment and Recall Definition

- Remove requirement for Long-Term evaluation to be completed within 10 business days (OP-3)
  - Increase in Long-Term outage submittals
  - Additional efforts in coordination to reduce reliability and economic impact
  - Projects and maintenance addressing transmission are reviewed regularly for schedule optimization
  - All requiring multi-party coordination

- Definition of Recall Time (OP-3)
  - Clarification given to measure the time in which ISO operations would request an outage to be restored to actual equipment re-energization

Next Steps

- Review the provided redline version of the ISO Tariff, Market Rule I - Appendix G and OP-3
- Direct all feedback to Jerry Elliott
- Implementation will be dependant upon change approval with Tariff, Market Rule 1 – Appendix G and OP-3
- Requesting review and vote at subsequent RC meeting

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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.

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

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

Asset-Specific Going Forward Costs are the net 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.13.7.2.7.1.1.2(a) of Market Rule 1.

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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 each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for

Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); 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.

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

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

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 July 14, 2014.

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

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

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

Capacity 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 July 14, 2014.

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 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.

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.

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

Common Costs are those costs associated with a Station that are avoided only 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 Resource is defined in Section III.13.1.1.2.3(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 estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

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

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

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

Day-Ahead 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 an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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 Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and 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 below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a 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, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

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

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

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

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.

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

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

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

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

Energy Non-Zero Spot Market Settlement Hours are 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.

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

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

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

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

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

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

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

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

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

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

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) cold Notification Time plus cold Start-Up Time 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.

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

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

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

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

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

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

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

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

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

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

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.

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

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

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

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

plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource 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, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 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 Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

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 Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is 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 or a Public Policy Transmission 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 Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 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 Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

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. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

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 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 Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

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 calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

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 Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (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.

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.13.1.1.2.1 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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

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 is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

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

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission

Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

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.13.7.2.7.1 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.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(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 Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource 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.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

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.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

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

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

Real-Time Congestion Revenue is defined in Section III.3.2.1(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 Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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 Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(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 Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 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 Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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 Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation 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.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, 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 Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

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).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

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

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System 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, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service

or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

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 (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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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 (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate 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 (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

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.

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 Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 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

SECTION III

MARKET RULE 1

APPENDIX G

REPAIR AND MAINTENANCE OF TRANSMISSION FACILITIES

APPENDIX G
REPAIR AND MAINTENANCE
OF TRANSMISSION FACILITIES
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This Appendix uses capitalized terms that are defined in the ISO's Transmission, Markets and Services Tariff and in the Transmission Operating Agreement.

III.G.1 Planning, Scheduling, and Approval of Transmission Facility Outages.

Throughout this Appendix G, in every instance in which the ISO is called upon to approve, schedule or reschedule transmission outages, it shall consider the generation outages proposed for the same time period for which proposed transmission outages are being considered and undertake the coordination procedures specified in the ISO New England Operating Procedures. In addition, Appendix G is to be construed throughout as reflecting that the ISO possesses the ultimate authority for approval, scheduling and rescheduling of transmission outages based on either reliability or market efficiency considerations (including any estimated or actual impacts on congestion or reliability-must-run costs in financial, day-ahead markets). The processes described in Sections III.G.1.1 through III.G.1.6, as further detailed in the ISO New England Operating Procedures, are those that the ISO will generally use to consider outage approval, scheduling and rescheduling, but shall not diminish or limit the ISO's ultimate authority as described in the preceding sentence.

III.G.1.1 Submittal of Long-Term Transmission Outages. Each Transmission

Owner shall submit to the ISO and the Local Control Centers for such Transmission Owner a projected, 12month schedule for the planned outages of such Transmission Owner's Category "A" Facilities, Other Transmission Facilities or Merchant Transmission Facilities. Each Transmission Owner shall also submit to the ISO and the Local Control Centers for such Transmission Owner a projected, 12month schedule for the planned outages of such Transmission Owner's Category "B" Facilities and Local Area Facilities, if any, if generator output could be affected by a planned outage of such transmission facilities. The process for the submission of Long-Term Transmission Outages and initial Local Control Center review and ISO study, as well as the rules governing the scheduling priority of an outage, are set out in the ISO New England Operating Procedures.

III.G.1.2 Reserved~~Scheduling of Major Transmission Outages.~~

~~A major transmission outage is a planned transmission outage of those transmission facilities that are expected to be modeled as a significant outage for purposes of an FTR auction, in accordance with the criteria for the modeling of such outages set forth in applicable ISO New England Operating Procedures.~~

~~The ISO shall notify the Transmission Owners and the Local Control Centers of those interim approved outages that satisfy the criteria for a major transmission outage. Additional details regarding the~~

~~scheduling of Major Transmission Outages are set out in the ISO New England Operating Procedures. To the extent that a Transmission Owner no longer intends to take an interim approved outage which satisfies the criteria for a major transmission outage in the time frame specified, the Transmission Owner shall notify the Local Control Center and the ISO as soon as practical and the outage will be cancelled.~~

III.G.1.3 Long Term Economic Approval of Transmission Outages.

Transmission Outages that are submitted to the ISO no later than 90 days prior to the start of the outage and receive interim approved status ~~shall~~may also receive long-term economic approval status, in which case the request may be denied or cancelled only for reliability reasons or due to unforeseen and extreme economic conditions.

III.G.1.4 Short-Term Approval of Transmission Outages.

The ISO shall confirm approval of all interim approved outages. Each Transmission Owner shall request planned outages of transmission facilities that have not been previously scheduled pursuant to Subsection III.G.1.1 by submitting requests for such approval to the Local Control Centers for such Transmission Owner, in accordance with applicable Local Control Center procedures and pursuant to the timelines and process set out in the ISO New England Operating Procedures. The ISO shall either approve such outages or, in the event the ISO determines that an outage should be repositioned, shall coordinate with each Transmission Owner and the applicable Local Control Centers for such Transmission Owner to reposition such outage to a time acceptable to the ISO, Local Control Center and the Transmission Owner, provided that the ISO shall have the authority to require the Transmission Owner to reposition an outage in accordance with Section III.G.2. All outages of transmission facilities that are approved by the ISO within this time frame shall be considered approved outages.

III.G.1.5 Real-Time Authorization to Commence Approved Outage.

Each Transmission Owner shall notify the ISO of such Transmission Owner's intent to commence or conclude an approved outage of a Category "A" Facility, Other Transmission Facility or Merchant Transmission Facility or an approved outage of a Category "B" Facility or Local Area Facility if generator output could be affected by the outage of such Category "B" Facility or Local Area Facility by submitting notification to the Local Control Centers for such Transmission Owner prior to the Transmission Owner's initiation of switching and tagging procedures to take the transmission facility out of service or place it back into service. The ISO shall either authorize such switching and tagging procedures or, in the event the ISO believes such outage should be repositioned, shall coordinate with each Transmission Owner and the applicable Local Control Centers for such Transmission Owner to

reposition such outages to a time acceptable to the ISO and the Transmission Owner, provided that the ISO shall have the authority to require the Transmission Owner to reposition an outage in accordance with Section III.G.2.

III.G.1.6

A Transmission Owner may propose to modify the timing of any interim approved or approved outage of its transmission facilities at any time. In the event a Transmission Owner proposes such a modification, the Transmission Owner must notify the ISO of the modified timing for such outage by submitting the notification to the applicable Local Control Centers for such Transmission Owner promptly after the circumstances have arisen that necessitate the modified timing. The Transmission Owner shall identify in such submission the generic category of circumstances giving rise to the modification, such categories to be determined by the Transmission Owners in consultation with the ISO. The ISO shall either accept the modified timing of an outage or coordinate with each Transmission Owner and the applicable Local Control Centers for such Transmission Owner to arrive at specific dates for each such outage acceptable to the ISO and the Transmission Owner in accordance with the process and time frames set out in the ISO New England Operating Procedures.

III.G.2 Authority of the ISO to Require the Repositioning of Transmission Outages.

The ISO possesses the ultimate authority for approval, scheduling and rescheduling of transmission outages based on either reliability or market efficiency considerations (including any estimated or actual impacts on congestion or reliability-must-run costs in financial, day-ahead markets). The processes described in Sections III.G.2.1 through III.G.2.4 are those that the ISO will generally use to consider outage rescheduling, but shall not diminish or limit the ISO's ultimate authority as described in the preceding sentence.

III.G.2.1

The ISO shall have the authority, at any time, to direct that an interim approved outage of a Transmission Owner's transmission facilities be repositioned or to revoke the approval of an approved outage of a Transmission Owner's transmission facilities if the outage reasonably could be expected to result in a violation of reliability criteria for the New England Transmission System and repositioning of the outage reasonably could be expected to improve reliability. The ISO shall notify the Transmission Owners whose transmission facilities are affected by the exercise of such authority of the ISO's decision to require the repositioning or revoke approval of the outage as soon as possible after the circumstances arise that create the need for the repositioning or revocation.

III.G.2.2

The ISO shall have the authority to direct that a Participating Transmission Owner outage be repositioned if repositioning the outage or revoking its approval reasonably could be expected to result in Significantly Reduced Congestion Costs for use of the New England Transmission System, where "Significantly Reduced Congestion Costs" means a reduction in the ISO's reasonable estimate of overall congestion and RMR costs for use of the New England Transmission System (net of the incremental cost to the Participating Transmission Owner) attributable to the outage in question of at least $200,000 for each week of an outage or any portion of a week. The ISO shall notify the Participating Transmission Owners whose transmission facilities are affected by the exercise of such authority of the ISO's decision to require the repositioning of the outage as soon as possible after the ISO determines that the criteria for requiring repositioning have been satisfied.

III.G.2.3

In exercising its authority under this Section III.G.2, the ISO shall consider the impact of directing the repositioning of interim approved and approved outages on the long term flexibility of operation of the transmission facilities and the New England Transmission System and the impact on system expansion needs in addition to any short term market impacts associated with the exercise of such authority.

III.G.2.4

The ISO shall coordinate with each Transmission Owner to determine mutually acceptable dates for the repositioning of any outage that must be repositioned due to the ISO's exercise of its authority under this Section III.G.2, provided that: (1) unless a Transmission Owner agrees otherwise, the ISO will generally allow the repositioning of any such outages within 90 days of the date the outage was originally scheduled, or, in the event that the 90-day period falls between June 1 and October 1, the ISO will generally allow the repositioning of any such outages during a period that begins no later than October 31; and (2) the requirement to allow the repositioning of such outages shall not limit the ISO's authority to require a further repositioning of the outage for reliability reasons in accordance with Subsection III.G.2.1 or for market efficiency reasons in accordance with Subsection III.G.2.2.

III.G.2.5

Upon request, the ISO shall provide the affected Transmission Owners with reasonable documentation and data supporting each exercise by the ISO of its authority to require the repositioning of outages or

revoke the approval of outages in accordance with Section III.G.2, subject to any applicable restrictions set forth in the ISO New England Information Policy on file with the Commission.

III.G.2.6

Notwithstanding any of the foregoing, nothing in this Section III.G.2 shall be construed to require a Transmission Owner to reposition an outage of a transmission facility or to require a Transmission Owner to refrain from initiating switching and tagging procedures to take a transmission facility out of service or place it back into service to the extent a Transmission Owner determines that such outage or actions are necessary to prevent injury or damage to persons or property or to protect its facilities from physical damage.

III.G.3 Annual Assessment of Outage Coordination Efforts.

An annual assessment of outage coordination efforts will be made as described in Section 3.08(c) of the Transmission Operating Agreement.

III.G.4 Market Monitoring of Outage Scheduling.

In accordance with Section III.A.9.4 of Appendix A of this Market Rule 1, 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.

ISO New England Operating Procedure No. 3
Transmission Outage Scheduling

Effective Date: draft

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References:

NPCC Directory #1 Design and Operation of the Bulk Power System (Directory #1), Appendix F: Procedure for Operational Planning Coordination, Facilities Notification List - Attachment D

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NPCC Directory #3, Maintenance Criteria for Bulk Power System Protection (Directory 3) ...

ISO New England Market Rule 1

Common System Dispatch Instructions for Hydro-Quebec, TransEnergie and ISO New England, ± 450 kV DC Lines Radisson-Nicolet-Sandy Pond (Phase II) GEN-C-040

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ISO New England Manual for Financial Transmission Rights Manual M-06 ...

Participants Agreement

Market Participants Service Agreement

Transmission Operating Agreement

Other Transmission Operating Agreements(s)

ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority (OP-1)

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ISO New England Operating Procedure No. 19 - Transmission Operations (OP-19)

ISO New England Operating Procedure No. 5 – Generator, Dispatchable Asset Related Demand and Alternative Technology Regulation Resource Maintenance and Outage Scheduling (OP-5)

Master/Local Control Center Procedure No. 7 - Processing Transmission Outage Applications (M/LCC 7)

Master/Local Control Center Procedure No. 15 - System Operating Limit Methodology (M/LCC 15)

SOP-OUTSCH.0030.0020 - Perform Short Term Outage Coordination

SOP-OUTSCH.0030.0025 - Perform Long Term Outage Coordination - Transmission

SOP-RTMKTS.0060.0020 - Monitor System Security

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Local Control Center Instructions:

CONVEX:	OI-0003 - Transmission System Work Control Process
Maine:	Maine Operating Procedure No. 3 - Maintenance of Facilities Operating at 34 kV and Above
New Hampshire:	OP-0003 Outage Application Requests
NSTAR:	OP 3 Outage Scheduling
REMVEC/NGRID:	REMVEC II Operating Procedure No. 3, Scheduling Outages of New England Control Center REMVEC Transmission Facilities
VELCO:	VELCO Operating Procedure OP-3 Outage/Maintenance Scheduling

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Appendices:

APPENDIX A - Retired (12/1/10)

APPENDIX B - Retired (06/10/11)

APPENDIX C - Retired (06/10/11)

APPENDIX D - Retired (12/1/10)

APPENDIX E - Retired (12/1/10)

APPENDIX F - Retired (12/1/10)

Attachment 1 through 9

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I. INTRODUCTION

A. BACKGROUND

Transmission outages for construction, tests, maintenance or repair must be coordinated to ensure that reliability is maintained at levels prescribed by ISO New England (ISO) Operating Procedure No. 19 - Transmission Operations (OP-19). In addition, whenever possible, transmission and Generator/ Dispatchable Asset Related Demand (DARD) outages will be coordinated to reduce congestion costs. For importing areas, economic Generators/ DARDs within the area should **not** be scheduled out simultaneous with transmission facilities that significantly support area import capability. For exporting areas, Generator/ DARD outages within the area should be coordinated coincident with the outage of transmission facilities that significantly support area export capabilities.

In addition, this procedure [ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3)] is to be construed throughout as reflecting that ISO possesses the ultimate authority for approval of proposed schedules and rescheduling of proposed or approved transmission outages based on either reliability or market efficiency considerations. The processes described in OP-3 are those that ISO will generally use to consider outage approval, scheduling and rescheduling, but shall **not** diminish or limit ISO ultimate authority as described in the preceding sentence.

B. PURPOSE OF PROCEDURE

The purpose of OP-3 is to achieve the following:

- Facilitate the preparation, by Transmission Owners (TOs) and Local Control Centers (LCCs), of TO Long-Term and Short-Term outage plans for their transmission facilities
- Establish a Long-Term and Short-Term Outage request process and a timeline for such outage requests.
- Coordinate transmission outages with Generator/ DARD outages to plan for reliable operations and minimize congestion
- Establish a Long-Term and Short-Term Outage scheduling process that does **not** jeopardize the reliability of the transmission system and continues to minimize congestion
- Provide guidelines for responding to unplanned outages

OP-3 defines Category A Facilities, Category B Facilities, Major Transmission Elements (MTE) and Local Area Facilities and establishes criteria and guides for submitting, evaluating, approving, and disapproving or repositioning all work on these facilities. A complete list and description of Category A and B Facilities under the ISO New England Transmission Operating Agreement can be found on the OASIS website. Whereas Local Area Facilities involve sub-transmission facilities (below 69kV) that have been delegated to LCCs within New England, a list of these facilities is **not** called for by the Transmission Operating Agreement (TOA) between ISO and TOs **nor** required for purposes of OP-3.

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II. DEFINITIONS

Definitions used in this Procedure:

"Capitalized terms used but **not** otherwise defined in OP-3 have the meanings ascribed thereto in the ISO Tariff, the ISO New England Manuals, the Second Restated New England Power Pool Agreement and the Participants Agreement."

- **Category A Facilities:**

  Category A Facilities as consisting of all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as Category B Facilities in accordance with the current TOA Categories of Transmission Facilities Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have Category A Facilities connected to the lower voltage side of the transformer; all transformers that require a Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

- **Category B Facilities:**

  Category B Facilities as consisting of all 115 kV radial transmission lines and all 69 kV transmission lines that are **not** interties between Control Areas; all transformers that have any Category B Facilities and **no** Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as Category A Facilities in accordance with the current TOA Categories of Transmission Facilities Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such Category B Facilities.

- **Congestion Costs:**

  The estimated increased expenses resulting from forecasted real-time commitment or re-dispatch of "out of merit" Generators/DARDs and/or the forecasted real-time re-dispatch or de-commitment of "in merit" Generators/DARDs in the Energy & Reserves Markets to respect operating criteria.

- **Local Area Facilities:**

  The transmission facilities of a Participating Transmission Owner within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have **no** Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer that are **not** listed in TOA Categories of Transmission Facilities Schedule 2.01(a), Schedule 2.01(b) and are **not** excluded facilities". Section 2.01(e)(iii) of the TOA defines Local Area Facilities as consisting of "all transmission facilities with a voltage level of less

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than 69 kV and all transformers that have **no** Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer.

- **Long-Term Economic Approval:**

  A Planned Transmission Outage request that is submitted greater than 90 days in advance of the start date and satisfies reliability and economic evaluations, receives economic approval status from ISO. Short of reliability concerns, it is intended to provide a level of assurance that the request will be denied / cancelled only under extreme economic conditions.

- **Long-Term Transmission Outage:**

  A Planned Transmission Outage that is requested at least 21 days in advance.

- **Major Transmission Elements (MTE)**:

  MTE are a subset of Category A Facilities and Category B Facilities that affect Generators/DARDs and may be further identified as, but **not** limited to, facilities defined or referenced in:

  - NPCC Facilities for Notification
  - Defined external interfaces
  - Defined internal interfaces
  - Restrictions on the operation of a Generator/DARD
  - A Transmission Operating Guide

  As a result of the above criteria, MTE (acting individually) may have a significant impact on the reliable and/or economic operation of the New England Transmission System and as a result, may have greater exposure to being cancelled or denied because of economic impacts than other transmission facilities.

  A list of MTE equipment is provided in Master/Local Control Center Procedure No. 7 - Processing Transmission Outage Applications (M/LCC 7).

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<#>**Major Transmission Outages:** ...

- **Planned Outage:**

  Transmission outage requests that satisfy the minimum advance notice times associated with either the Long-term or Short-term Transmission Outage processing.

- **Recall Time:**

  The measured time from when ISO/LCC requests an LCC/TO to safely restore a transmission element from outage state to in service.

- **Short-Term Transmission Outage:**

  Planned Transmission Outage submitted for ISO Approval less than 21 days and greater than 120 hours prior to 0001 the day the outage is scheduled to begin.

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- **Significantly Reduced Congestion Costs:**

  Reductions in forecasted real-time congestion and RMR costs resulting from the repositioning of a transmission outage are considered significant when the reduction minus the Participating Transmission Owner's incremental direct costs for repositioning the outage exceeds $200,000 per week or any portion of a week.

- **Transmission Outage Request Flags**:

  One or more of the following additional identifiers may be associated with each outage to set outage priority as described in this definition section.

  - **Long-Term Economic Approval**
  - **Outage Overrun**

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<#>Major Transmission Outage ...

- **Transmission Outage Request Status:**

  One of the following:

  - **Active Status**
    - **Preliminary:** Planned Transmission Outage provided to ISO for informational purposes only; **no** studies shall be conducted until the outage has been moved to the status of Submitted
    - **Submitted:** Transmission outages prepared for ISO study and acceptance and awaiting Interim Approved Status or Approved Status
    - **Study:** Transmission outages actively being studied and evaluated by ISO to determine Interim Approved Status or Approved Status
    - **Negotiate:** Transmission outages under additional review and pending repositioning
    - **Interim Approved:** Transmission outages that have been studied and accepted by ISO through the Long-Term Transmission Outage process but waiting final Approved status through the Short-Term Transmission Outage Process
    - **Approved:** Transmission outages studied and accepted by ISO in accordance with the Short-Term Transmission Outage process
    - **Implemented:** Transmission outage that has begun, reflecting equipment taken out of service or in an abnormal state
  - **Non-Active Status**
    - **Withdrawn:** Preliminary Transmission outages that are **no** longer planned by the Transmission Owner or have lapsed within 21 days prior to the start date
    - **Denied:** Transmission outage requests which have **not** been Approved

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- **Cancelled:** Previously Approved Transmission outages (Interim Approved or Approved) that have been called off by the TO, LCC or ISO.
- **Completed:** A Transmission outage that had been returned to service

- **Unplanned Outage:**

  This is any outage that fails to satisfy the lead times required for Short-Term Transmission Outage processing. There are four types of Unplanned Outages:

  1. **Emergency Outage**

     The obvious failure of a piece of transmission equipment that comes out of service on its own or requires immediate operator intervention to remove it from service.

  2. **Forced Outage**

     The discovery of a problem that needs to be repaired as soon as crews, equipment, and/or corrective dispatch actions can be put in place to allow the work to be performed. By definition, a Forced Outage **cannot** be scheduled. More specifically:

     - A Forced Outage **cannot** be delayed to avoid paying overtime rates; e.g., on a Friday, delaying a Forced Outage until Monday, rather than performing the work on Saturday. This implies that a Forced Outage must occur on consecutive days, except in the case described in the next bullet
     - A Forced Outage **cannot** schedule an Alternate Date. If weather impairs safe work conditions, the outage can be moved to the next available fair weather day, and the planned end date/time shall be extended
     - An Opportunity Outage that unexpectedly causes additional adverse impact on either system reliability or market efficiency beyond that which was originally anticipated. Typically this would be associated with the unexpected extension of the defined timing parameters.

  3. **Overrun Outage**

     This is any outage that fails to return to service by its planned end time, and the outage has extended into the next calendar day.

  4. **Opportunity Outage**

     This is an outage that is submitted for ISO Approval as a result of an unexpected opportunity to accomplish work that would otherwise require another outage at a less opportune time. This is most often initiated by but **not** limited to a Generator/DARD Unplanned Outage or expedited completion of a Transmission or Generator/DARD outage or project. It shall be coordinated to minimize the overall impact on system reliability and /or market efficiency.

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III. AUTHORITIES AND RESPONSIBILITIES

A. ISO AUTHORITIES AND RESPONSIBILITIES

ISO shall:

- Receive from LCCs, Long-Term and Short-Term Transmission Outage requests that were **not** disapproved by the LCCs, for all Category A Facilities, and for Category B Facilities if Generator/DARD output could be affected by the outage. Outage requests for Local Area Facilities that affect Generator/DARD output shall be processed using LCC and ISO OP-5 scheduling practices.
- Review proposed outages in the Long-Term and Short-Term Transmission Outage requests and compare them to Generator and DARD outage plans as follows:
  - Evaluate the impact of proposed transmission outages on the reliability of the New England RCA/BAA power system operations. Reposition or disapprove any outage that could be expected to violate reliability criteria for the New England Transmission System and for which repositioning the outage could reasonably be expected to improve reliability.
  - Work with LCCs to adjust Generator/DARD and transmission outages to minimize congestion costs. When warranted, and time permitting, perform economic analyses of outage alternatives to define and examine potential congestion costs. Reposition the outage if Significantly Reduced Congestion Costs are feasible, or where lesser congestion reduction is available and the TO(s) agree.
  - Have the authority to reposition or disapprove any outage that adversely impacts market efficiency.
  - Support outage scheduling related communications between TOs and Generator/DARD owners to assure affected parties are appropriately notified in a timely manner.
- Appropriately notify LCCs and Market Participants of action regarding outage requests.
- Assign to the LCCs the function of receiving, evaluating, approving or disapproving transmission outage requests submitted by a TO, with respect to its impact on the reliability and congestion of LCC operations.
- Promote the continuous flow of information between ISO, LCCs, and TOs to match pending transmission outage work with planned or forced Generator/DARD outages to the extent practicable.
- Monitor the outage positioning activities of the TOs. ISO shall have the right to request that a TO provide information to the ISO Market Monitoring Unit concerning any TO positioning of transmission facility outages, including the repositioning or cancellation of any Planned, Scheduled or Approved Outage .

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- Assign each Long-Term and Short-Term Transmission Outage request a number, date stamp and Status. In general, the number, date stamp and Status will be used, if needed, to prioritize outage requests. ISO will attempt to resolve conflicting Long-Term and Short-Term Transmission Outage requests through discussions with the affected LCCs. When discussions **cannot** resolve the conflict, the Long-Term and Short-Term Transmission Outage that was Submitted earliest shall have priority.

- Post and maintain a list of requested outages with corresponding Status on the ISO Web Site within the limitations of the ISO Information Policy.

NOTE

In accordance with the ISO New England Information Policy and to avoid the potential exercising of market power by any entity, outages that obviously restrict a Generator/DARD (such as radial circuits to Generators/DARDs) will **not** be posted.

B. LCC AUTHORITIES AND RESPONSIBILITIES

LCCs shall:

- Receive TO Long-Term and Short-Term Transmission Outage requests from TOs for all Category A Facilities, and for Category B Facilities if Generator/DARD output could be affected by the outage. Outage requests for Local Area Facilities that affect Generator or DARD output shall be processed using LCC and ISO New England Operating Procedure No. 5 – Generator, Dispatchable Asset Related Demand and Alternative Technology Regulation Resource Maintenance and Outage Scheduling (OP-5) scheduling practices

- Prior to submitting proposed outages to ISO for final evaluation and approval, review proposed Long-Term and Short-Term Transmission Outage requests and compare them with Generator/DARD outage plans and requests received from ISO as follows:

  - Evaluate the impacts of proposed transmission outages on the reliability of LCC operations. Reposition or disapprove any outage that could be expected to violate LCC reliability criteria and for which repositioning the outage could reasonably be expected to improve reliability

  - Identify and pursue cases where Generator/DARD and transmission outages could be adjusted to reduce/eliminate Congestion Costs and overall outage duration. In each case, LCCs will facilitate/coordinate outages as detailed in Section VI.B.1 of this procedure to achieve Significantly Reduced Congestion Costs, or to achieve lesser congestion reduction if the TO(s) agree.

- Forward Submitted Long-Term and Short-Term Transmission Outages to ISO for further evaluation and coordination

- Transmit ISO actions regarding outage requests to TOs

- Perform dispatching functions for all Category B and Local Area Facilities if Generator/DARD output is **not** affected by the outage, if assigned that

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responsibility by its Market Participants

- Promote a continuous flow of information between ISO and TOs to match pending transmission outage work with Generator/DARD outages to the extent practicable
- Verify that **non**-public transmission outage information and outage information associated with other Generators/DARDs is **not** shared with the Generator/DARD Owners contacted
- Refrain from engaging in multi-party communications simultaneously with Generator/DARD and TOs unless the transmission outage of concern only affects one Generator/DARD owner

C. TO AUTHORITIES AND RESPONSIBILITIES

TOs or their designees shall:

- Submit their proposed or updated transmission outage plans to their respective LCC and provide as much information as possible on the flexibility of shifting the requested period forward or backwards
- Work with LCCs and ISO to provide alternate outage dates when it is determined that congestion could be eliminated or reduced by doing so
- Propose changes to any requested outage promptly after circumstances develop and submit reasons for the change to the LCC
- When requested, submit information concerning the TO positioning of transmission facility outages to ISO
- Coordinate with Market Participants the request for planned and unplanned testing and maintenance outages of relay protection systems that could reduce or impact normal operation
- Participating TOs will provide information regarding their direct costs for canceling outages to their LCC and ISO when requested.

NOTE

Participating Transmission Owners staff working on transmission outages may be provided with Generator/DARD outage information to assist in the establishment of outage plans and determining alternate dates. The Participating Transmission Owner staff working on transmission outages shall **not** disclose this information to other parties.

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IV. ROUTING TRANSMISSION OUTAGE REQUESTS

The TO or Market Participant requesting work on transmission facilities covered by OP-3 shall initially submit a transmission outage request to the appropriate LCC. This section describes the subsequent routing of transmission outage requests.

1. Facilities solely under the Jurisdiction of the LCC:

   Category B Facilities **not** affecting Generator/DARD output and all Local Area Transmission Facilities are under the jurisdiction of the LCC. The handling of outages for these facilities is a LCC function. Transmission outage requests are acted upon by the LCCs and need **not** be forwarded to ISO; however outages involving Local Area Facilities affecting a Generator/DARD shall be processed using LCC and ISO OP-5 scheduling practices. Outages involving Category B Facilities **not** affecting a Generator/DARD shall be sent to ISO in a daily summary sheet.

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2. Facilities requiring assessment by the LCC and ISO:

   Unless the LCC disapproves the transmission outage request, the LCC shall review, study and record assumptions and results for Category A and Category B Facilities prior to forwarding to ISO for assessment.

3. Inter-LCC and Inter-Area Facilities:

   Because of the special communication requirements that apply when Transmission Outage requests involve Inter-LCC (i.e., facilities crossing LCC boundaries but **not** leaving the New England RCA/BAA) and Inter-RCA/BAA facilities, the LCC and ISO shall coordinate these transmission outage request as follows:

   - **Inter-LCC facilities:** The LCC shall forward transmission outage request to the adjacent LCC and to ISO for approval or disapproval
   - **Inter-RCA/BAA facilities - NYISO and New Brunswick System Operator (NBSO):** The LCC shall forward requests to the appropriate adjacent system's dispatch agency and to ISO. ISO shall forward requests to the appropriate NPCC Reliability Coordinator/Balancing Authority (RC/BA) for approval or disapproval
   - **Inter-RCA/BAA facilities - TransEnergie:** The LCC shall forward requests to ISO. ISO shall perform all coordination with TransEnergie. Requests shall be forwarded to TransEnergie for approval or disapproval

4. Transmission outage requests initiated outside the New England RCA/BAA

   Requests initiated by systems outside the New England RCA/BAA for work on inter-RCA/BAA facilities will first be communicated from the outside company to the involved LCC. If the LCC and outside company agree to times and dates for an outage, the outside company will forward the application to its NPCC RC/BA who will assess the application and if approved, forward it to ISO for approval under Section V or VI. ISO will notify the appropriate LCC.

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5. Facilities on the NPCC Area Facilities for Notification List

   In addition to inter-RCA/BAA facilities, there are other facilities in each NPCC RCA/BAA that, if taken out-of-service, can affect adjacent RCAs/BAAs. These facilities are listed in the document entitled, NPCC Directory #1 Design and Operation of the Bulk Power System, Appendix F: Procedure for Operational Planning Coordination, Facilities Notification List - Attachment D. ISO shall forward transmission outage requests received from the LCCs, involving the New England RCA/BAA facilities listed in NPCC Directory #1, Appendix F, Attachment D, to the appropriate NPCC RCs/BAs for approval or disapproval. Requests received by ISO from adjacent NPCC RCAs/BAAs, involving NPCC RCA/BAA facilities which can affect the New England RCA/BAA transmission system, shall be reviewed by ISO for approval under Section V or VI and reported to the appropriate LCCs.

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V. LONG-TERM TRANSMISSION OUTAGE REQUESTS

A. SCOPE OF LONG-TERM TRANSMISSION OUTAGE REQUESTS

Long-Term Transmission Outage requests shall include Category A Facilities and Category B Facilities that affect Generator(s)/DARD(s). The outage of any associated equipment including breakers, disconnects, shunts, SVCs, STATCOMs, series reactors or capacitors, PARs, SPSs, Relays and Reclosing must also be reported.

Unless cancelled, Interim-Approved Long-Term Transmission Outages shall automatically progress into the Short-Term Outage process, as described in Section VI of this Procedure.

B. MINIMUM ADVANCED NOTICE TIME-RESPONSE TIME FOR LONG-TERM TRANSMISSION OUTAGES

In accordance with LCC procedures, TOs or their designees shall submit their proposed or updated Long-Term Transmission Outages for all Category A Facilities and Category B Facilities if a Generator/DARD output could be affected by the outage. The LCCs or their designees shall submit the outage request in the Preliminary status to ISO. ISO will **not** take any action to study or coordinate outages with Preliminary status. Preliminary status shall be considered informational only and will **not** set scheduling priority based on timestamp. Preliminary status shall **not** be accepted within 21 days of the start date of the outage and any outages that were previously submitted and remain in Preliminary status shall be automatically withdrawn at 21 days prior to the start date. It is expected that once the TO confirms these outage plans with the LCC, that the request will be put into the Submitted status.

The LCCs shall provide Long-Term Transmission Outage requests in Submitted status that have been studied, approved and provide appropriate documentation as described in this procedure. This indicates to ISO that the transmission outage request is ready for ISO study and establishes the timestamp used in setting scheduling priority. Submitted Long-Term Transmission Outage requests shall be accepted **no** sooner than 24 months and **no** later than 21 days prior to the start date of the transmission outage.

ISO shall study transmission outage requests in the Submitted status. Prior to the ISO study, efforts to review and coordinate outages to reduce reliability and economic impact are underway. Once the ISO study begins or until the request is terminated, details of the outage request will be locked from any changes initiated by the LCC. ISO may require cancellation and/or a new submittal if significant changes are requested by the LCC. If further information supporting the outage is required, ISO will place the outage in Negotiate. Upon study completion, ISO shall apply a status of: Interim Approved or Denied and respond to the appropriate LCC.

Long-Term Transmission Outage requests Submitted to ISO at least 90 days prior to the start of the outage, if approved through reliability studies may also be subjected to economic studies and possible repositioning. Facilities identified as MTE may be subjected to economic studies and possible repositioning. The

Deleted: and respond to the appropriate LCC **no** later than 10 business days after Submittal, not including business days that fall within the Transmission Outage Review Moratorium. See Section V.C. below. In response the

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Deleted: or Negotiate. Once studies begin and until the request is terminated, the details of the outage request will be locked and any changes in dates or equipment will require cancellation and a new submittal

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process of Submitting Long-Term Transmission Outage requests involving an MTE facility at least 90 days prior to the start date of the outage does **not** ensure that it will be Approved **nor** does it set any scheduling priority over any other previously Submitted transmission outage request. However, once such a request is approved for economics the applicant will have greater assurance that it will **not** be cancelled at a later date due to economic impacts.

A transmission outage request that is Submitted to ISO at least 21 days prior to the start date of the outage and is approved for reliability will receive Interim Approval Status.

A transmission outage request that is Submitted to the ISO at least 90 days prior to the start date of the outage, approved for reliability and selected for economic study and ultimately approved shall receive the flag Long-Term Economic Approval.

A transmission outage request that is Submitted to ISO less than 90 days prior to the start date of the outage and is given the status of Interim Approved through the Long-Term Transmission Outage process may be subjected to economic studies and possible repositioning in the Short-Term Transmission Outage process. These transmission outages will be at risk for cancellation for economic impact up to the time the outage actually begins.

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C. LONG-TERM TRANSMISSION OUTAGE REVIEW MORATORIUM

1. Annual Forward Capacity Market Reliability Review

   a. During the period when ISO-NE is performing reliability reviews of FCM annual bilateral submissions for the upcoming FCM Capacity Commitment Period; Long-term Transmission Outage requests for outages that fall within June 1st through September 15th of the FCM Capacity Commitment Period will be time stamped to establish review priority and held until the FCM bilateral reliability review process is completed.

      (1) Annual Bilateral reliability review period begins immediately following the close of the Annual Bilateral submission period for the applicable FCM Capacity Commitment Period.

   b. During the period when ISO-NE is performing reliability reviews of the FCM 3rd annual reconfiguration auction results for the applicable FCM Capacity Commitment Period, Long-term Transmission Outage requests for outages that fall within June 1st through September 15th of the FCM Capacity Commitment Period will be time stamped to establish review priority and held until the auction results reliability review is completed.

2. Monthly FCM Reliability Review

   a. During the period when ISO is performing reliability reviews of FCM monthly bilateral submissions and monthly reconfiguration auction results for the applicable month, Long-term Transmission Outage requests for outages that fall within the applicable month will be time stamped to establish review priority and held until the reliability review process is completed.

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D. REPOSITIONING OUTAGE REQUESTS

ISO and LCCs, working with TOs, and Generators/DARDs, shall reposition outages; 1) that could be expected to violate reliability criteria or, 2) to reduce or eliminate Congestion Costs.

ISO and LCCs during their review can reposition the facility outage of a TO if it could be expected to violate reliability criteria. During their review, ISO and LCCs can also reposition the facility outage of a Participating Transmission Owner if it could be expected to achieve Significantly Reduced Congestion Costs. Furthermore, an outage may be repositioned to avoid net costs less than the $200K threshold if agreed to by the involved TO(s).

ISO and the LCC, working with the Participating Transmission Owner, will generally reschedule, within 90 days of the original schedule, any transmission outage requiring repositioning for reliability violations or to achieve Significantly Reduced Congestion Costs. In the event that the 90-day period falls between June 1st and September 15th, ISO and the LCCs will generally reschedule such transmission outages during a period that begins **no** later than October 31st.

TOs can propose changes to transmission outage requests. The TO must notify the applicable LCC promptly after circumstances develop that necessitates such a change. The notification will include a description of the circumstances that led to the change request. The LCC will promptly forward the information to ISO. Changes to transmission outage requests may result in a requirement to submit a new request, sacrificing any scheduling priority and shall be subject to ISO Market Monitoring and Mitigation review.

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E. REPORTS - LONG-TERM TRANSMISSION OUTAGES PROJECTED OUT 24 MONTHS

ISO shall create and maintain a New England Long-Term Transmission Outage Report and post the report daily on the ISO web-site in accordance with the ISO New England Information Policy. This report shall incorporate outages in the following states, Preliminary, Submitted, Study, Negotiate and Interim-approved for the time frame beginning 24 months in advance of the current day and ending within 21 days of the current day.

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VI. SHORT-TERM TRANSMISSION OUTAGE REQUESTS

A. MINIMUM ADVANCE NOTICE TIME - RESPONSE TIME FOR SHORT-TERM TRANSMISSION OUTAGES

Outages of transmission facilities may require extensive study and coordination, first by the LCC to assess local area reliability and perform rudimentary congestion analysis and then by ISO to assess bulk power system reliability and perform warranted detailed congestion analysis. Operating policies at the LCCs define minimum advance notice times for the submittal of outage requests from the TOs to the LCCs. These notice times are critical and designed to provide the LCCs with enough time to assess TO outage requests before denying them or forwarding them to ISO for further analysis and ultimate approval.

Similarly, ISO needs enough time to assess the outage requests and deny or approve them. Furthermore, approved outages must be known in time for use in the settlement of the Day Ahead Markets (DAMs), and TOs must know in time to coordinate final steps to arrange equipment and manpower needed to do the work. To provide adequate time for this analysis and coordination, application advance notice times, and ISO response times, have been established.

Transmission Facilities

1. In general, all Category A Facility outages and Category B Facility outages that affect a Generator/DARD shall require the submittal of a Short-Term Transmission Outage application. LCCs and neighboring RCs/BAs shall submit Short-Term Transmission Outage applications for these facilities to ISO at least one hundred and twenty (120) hours prior to 0001 on the day when work is to begin (Example: An outage positioned to begin at 0800 on Monday must be submitted to ISO before 0001 on Wednesday the week prior.) ISO shall approve/disapprove requests at least 24 hours prior to 0001 on the day the work is to begin. ISO shall also have the authority to waive either of these timeframes.

2. To facilitate the submittal of transmission outage requests for specific transmission facilities, a detailed guide is provided in M/LCC 7. The format of the guide goes by voltage level and the type of transmission facility, which is a natural logic structure for considering transmission facilities. Minimum advance notice times are given for each type of facility. These times reflect the practical application of facility categories defined in this document.

3. LCCs do **not** have to submit requests to ISO for outages involving Local Area Facilities. However, outage requests for Local Area Facilities that affect a Generator/DARD output shall be processed using LCC and OP-5 scheduling practices.

   In general, complex outages, particularly those involving more than one LCC and/or dispatch entities outside the New England RCA/BAA, will require significantly longer coordination efforts. Consequently, discussions of these outages by involved parties must begin several months early to coordinate the system for the expected work. General information on these outages will first be submitted by the TOs via the Long-Term Transmission Outage process. Details

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on these outages shall be submitted to LCCs and in turn to ISO as soon as TOs have finalized arrangements.

B. SHORT-TERM TRANSMISSION OUTAGE REVIEW AND APPROVAL PROCESS

LCC Review and Action:

1. Upon receipt of requests for work on Category A Facilities or Category B Facilities that affect Generator/DARD output, the LCC shall perform the following:

   a. Prior to submittal for ISO Short-Term Outage Request approval, the LCC shall review all Scheduled Outages and Short-Term Transmission Outage requests and compare them with Generator/DARD outage requests received from ISO. Evaluate outage requests to assure reliable operation. Disapprove any outage request that violates LCC operating procedures or is determined to be in violation of ISO Operating Procedures and/or Transmission Operating Guides (TOG).

   b. Prior to submittal to ISO for Short-Term Outage Request approval, the LCC shall, working with ISO, identify cases where Generator/DARD and transmission outage positions could potentially be adjusted to achieve Significantly Reduced Congestion Costs, or (with TO consent) where lesser congestion reduction can be achieved. In each case, facilitate/coordinate repositioning as follows:

      (1) Discuss and assess the preliminary plan for outage repositioning with ISO

      (2) Contact the TO for additional flexibility in their timing of the outage. (Generator/DARD outage information can be discussed with the Participating Transmission Owner as required).

      (3) After consulting with the TO, if needed, proceed as follows depending on whether the case involves; i) an importing area, ii) Generator/DARD or exporting area involving a single owner or, iii) an exporting area involving multiple Generators/DARDs owned by multiple Owners.

         (a) Importing Local Area

         For an importing local area, the simultaneous outage of transmission supplying the local area along with Generator(s)/DARD(s) within the local area can increase congestion and, in severe cases, jeopardize system reliability. To relieve this, the following actions will be taken to try to position the transmission, generation and DARD outages so that they occur at different times:

         - Contact the applicable Generator/DARD Owners to determine if there is additional flexibility in their outage position
         - Contact the TO for additional flexibility in their position. (Generator/DARD outage information can be discussed with the Participating Transmission Owner as required.)

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- If required, continue to alternately contact the TO and the Generator/DARD Owner until a determination is made by ISO on whether or **not** activities can be positioned to reduce/eliminate congestion

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NOTE

If actions above are **not** sufficient to relieve congestion, ISO will dispatch Generators/ DARDs in accordance with the congestion management process or change the timing of the transmission outage.

(b) Generator/DARD or Exporting Local Area Involving a Single Owner

This scenario involves a transmission outage that will restrict the commitment or dispatch of Generators/DARDs owned by a single company (i.e. a line leaving a generating station). The following actions will be taken as soon as possible to try to change or create outage positions so that Generators/DARDs and transmission outages occur simultaneously, thereby relieving the potential locked-in Generators/DARDs.

- Contact the applicable Generator/DARD owner to determine if there is additional flexibility in their outage application. If the transmission outage involves a radial circuit to a Generator/DARD, details about the transmission outage can be shared with the Generator/DARD Owner. Additionally, **non**-radial transmission outage information can be shared with the Generator/DARD Owner if the transmission outage solely affects that Generator/DARD Owner

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- Contact the TO for additional flexibility in their timing of the outage. (Generator/DARD outage information can be discussed with the Participating Transmission Owner as required.)
- If required, continue to alternately contact the Participating Transmission Owner and Generator/DARD owner until a determination is made by ISO on whether or **not** activities can be positioned to reduce/eliminate congestion

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- The Participating Transmission Owner may contact the Generator/DARD Owner directly to facilitate positioning of outages

(c) Exporting Local Area Involving multiple Generators/DARDs owned by multiple companies

This case involves a transmission outage that will restrict the commitment or dispatch of Generators/DARDs within an exporting local area that contains several units owned by different Generator/DARD owners. The following actions will be taken to try to change or create outage positions so that Generators/DARDs and transmission outages occur simultaneously, thereby relieving the

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potential locked-in Generator/DARD.

- Contact the applicable Generator/DARD owners to determine if there is additional flexibility in their outage position in the order that their outage request was received
- Contact the TO for additional flexibility in their position. (Generator/DARD outage information can be discussed with the Participating Transmission Owner as required.)
- If required, continue to alternately contact the TO and Generator/DARD owners until a determination is made by ISO on whether or **not** activities can be positioned to reduce/eliminate congestion
- If units with outage requests are exhausted or **no** outage requests exist, contact affected Generator/DARD owners randomly, in a manner to be determined by the LCC, without preference to any one Generator/DARD owner. Inform each Generator/DARD owner that a transmission outage (**no** details) may result in their unit being restricted and determine if they desire to coordinate an outage of their unit with the transmission outage
- If required, continue to alternately contact the TO and Generator/DARD owners until a determination is made on whether or **not** activities can be positioned to reduce/eliminate congestion costs

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NOTE

If actions above do **not** alleviate constraints, ISO will dispatch Generators/DARDs in the constrained export area based on its congestion management process or change the position of the transmission outage.

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c. Once the transmission outage has initial approval, either with or without a corresponding Generator/DARD outage: 1) notify adjacent LCCs and/or systems outside of the New England RCA/BAA that may be affected by the requested work, and 2) forward the application to ISO with the following information:

(1) Facility (name and nomenclature).

(2) Reason for application (work to be done).

(3) Emergency restoration time in hours.

(4) Time and date switching is to begin.

(5) Time and date the facility is to be restored to normal operation.

(6) LCCs and/or systems outside of the New England RCA/BAA to whom

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notifications have been given.

(7) Other information pertinent to the application that may affect ISO decision, such as a request to revise a Generator/DARD outage schedule to address congestion issues with the transmission outage.

(8) LCC analysis results and approval including contingencies and limiting elements, local voltage constraints, must run Generators/DARDs and restricted Generators/DARDs.

NOTE

Requests submitted by adjacent NPCC RCs/BAs must also be accompanied by information listed in items (1) through (8) above.

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2. ISO Review and Reliability Study for Short-Term Transmission Outages:

   Upon receipt of requests from a LCC for Short-Term Transmission Outages, ISO shall:

   a. Assign the application an identification number.

   b. Forward requests involving inter-RCA/BAA or NPCC Directory #1, Appendix F, Attachment D facilities to the appropriate NPCC RC/BA for approval or disapproval.

   c. Inform, as required, other LCCs or NPCC RCs/BAs.

   d. Conduct reliability studies in sufficient detail to:

      (1) Identify the more severe probable first contingencies (there may be several).

      (2) Identify voltage constraints and thermally limiting contingencies and elements, expected flows on limiting elements, ratings [Normal, Long-Term Emergency (LTE), Short-Term Emergency (STE), Drastic Action Limit (DAL),] of limiting elements and provide distribution and adjustment factors. Determine if any pre-defined stability constraints must be followed.

      (3) Document system Generator/DARD patterns and transmission configurations expected during the time work is to occur, i.e., Generators/DARDs and transmission facilities out of service, Generators/DARDs required to be in service, etc.

      (4) Interchange schedules, flows across pre-determined interfaces and/or flows on major inter-RCA/BAA tie lines.

      (5) Determine action required prior to beginning work and after work has begun to ensure compliance with OP-19.

      (6) Determine bulk power supply area protection Generator/DARD requirements (units and energy availability).

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(7) Determine "locked in" Generators/DARDs. Include Generators/DARDs that must be left off-line, and online Generators/DARDs that must be dispatched at reduced loads.

e. Transmission outage requests with the Status of Submitted and Study should be repositioned before an Approved or Interim Approved outage is repositioned. Outage priority is established in Section VIII of this procedure.

f. With respect to routine transmission or Generator/DARD maintenance, in the event that a Generator/DARD outage conflicts with a requested transmission outage, the Generator/DARD outage will normally have priority except in the 7 days immediately preceding the start of the transmission outage in which case the outages will be prioritized according to the time at which the outage request is received. ISO may adjust this priority due to reliability concerns.

g. Obtain approval or disapproval from adjacent NPCC RC/BA, if applicable.

h. Approve or disapprove the request

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C. NOTIFICATIONS

When the review and assessment has been completed, ISO will communicate its conclusions to the appropriate LCCs and/or adjacent NPCC RCs/BAs. ISO will notify those LCCs and adjacent NPCC RCs/BAs that received preliminary notification of the requested work, even if that notification was from an agency other than ISO. If a Generator/DARD outage position or reduction was revised or initiated during processing of the transmission outage request (i.e., to eliminate congestion), ISO will contact the Generator/DARD owner to confirm the revision to their position.

1. Notification in case of Approval

   When approving an outage request, ISO shall provide the conclusions of its reliability study in sufficient detail that all affected systems recognize the impact of the approved work. The conclusions should cover at least those items listed in Section VI.B.2.d.

2. Notification in case of Disapproval

   When giving an outage request disapproval notification, ISO shall state the reasons for disapproval. Those reasons shall be specific and relate to items listed in Section VI.B.2.d or to achieve Significantly Reduced Congestion Costs.

   Once a request for outage approval is disapproved, that request is considered completed. To accomplish the work, a new request must be submitted as described in Section VI.D.

3. Notification in case of Cancellation

   An LCC or an adjacent NPCC RC/BA may subsequently cancel a request for work on a New England RCA/BAA transmission facility that has been forwarded to ISO.

   The party initiating such action shall determine and communicate to other affected parties the specific reasons for the cancellation

   Once cancellation has been made, the request is considered completed. ISO shall notify the appropriate LCCs and adjacent NPCC RCs/BAs of the request's status change. To accomplish the work, a new request shall be submitted as described in Section VI.D.

4. Posting of Short-Term Transmission Outages

   ISO shall post all approved Short-Term Transmission Outages on the ISO Web Site in accordance with the ISO Information Policy. Any revisions shall be updated on the web site in a timely manner.

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D. RE-SUBMITTAL

To request approval of work that has been Denied or Cancelled, a new request with a new request number and a new review and reliability study shall be processed as though **no** previous request had been provided.

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The one exception to this is when an "Alternate Date" has been supplied on the original request form. The “Alternate Date” is the working day following the last date for the outage. In the event the "Alternate Date" is used for repositioning the work, the existing request will be used and all necessary review and study shall again be processed for this work to be performed on the "Alternate Date".

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VII. UNPLANNED OUTAGES

A. SUBMISSION OF REQUESTS

The following describes processes for providing requests (which will be processed per Section VI of this procedure) for the three different types of Unplanned Outages.

1. **Emergency Outage**

   Market Participants shall submit requests for Emergency Outages of transmission facilities immediately to the LCC. If the request is for Category A Facilities or Category B Facilities, the LCC shall immediately forward the request to ISO.

2. **Forced Outage**

   Market Participants shall notify their LCC as soon as the need for a Forced Outage is identified. The LCC shall immediately notify ISO about the Forced Outage. The Forced Outage should **not** be officially submitted until the LCC has reasonable assurance from the Market Participant that system conditions, crews and equipment are available for the job.

3. **Overrun Outage**

   Market Participants shall notify their LCC as soon as the need for an Overrun Outage is identified and the LCC shall immediately communicate this information to ISO.

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4. **Opportunity Outage**

   Market Participants shall notify their LCC as soon as an Opportunity Outage is identified. Prior to submittal for ISO Short-Term Outage Request approval, the LCC should study the proposed Opportunity Outage as described in Section VI.B. The Opportunity Outage request should **not** be officially Submitted until the LCC has reasonable assurance from the Market Participant that system conditions, crews and equipment are available for the job.

   Opportunity Outage requests shall be submitted to ISO **no** more than one hundred and twenty (120) hours prior to 0001 on the day when work is to begin and **no** less than twenty-four (24) hours prior to 0001 on the day when work is to begin. This will ensure proper studies are completed and if approved, Opportunity Outages are included in the DAM transmission topology assumptions. Opportunity Outages shall **not** be permitted that impose additional restrictions on MW resources (Generators/DARDs and/or inter-ties) that would **not** otherwise exist in the absence of the Opportunity Outage.

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   Opportunity Outage requests submitted to ISO must adhere to the following additional conditions:

   - Restoration (recall) time, **not** to exceed 4 hours
   - Limited duration, **not** to exceed one 96 hour period

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- In the event the transmission outage once underway unexpectedly exceeds this additional timing criterion, the entire outage shall be converted to Forced
- Receives the lowest priority when competing with all other outage types Planned or Unplanned

B. RESPONSE TO UNPLANNED OUTAGES (DOES NOT APPLY TO OPPORTUNITY OUTAGES)

If time exists while crews, equipment, and/or corrective dispatch action arrangements are being made, the LCC shall provide ISO with all pertinent information to allow for study of the outage and prioritization with other dispatch requirements.

In either event, the flow of information regarding the Unplanned Outage shall follow the outlines shown on Attachments 1 through 9. The timing requirements and various approval steps do **not** apply to most Unplanned Outages. Unplanned Outages shall be subject to ISO Market Monitoring and Mitigation review.

C. UNEXPECTED RELAY OUTAGES

ISO has identified certain relay protection systems that require additional notification to PRC_Review@iso-ne.com when remaining Out-of-Service. Refer to Master/Local Control Center Procedure No. 15 - System Operating Limits Methodology (M/LCC 15) and the M/LCC 15 Attachments for identification of affected protective relay groups and M/LCC 7 and the M/LCC 7 Attachments for the reporting process and required information. The purpose of providing detailed information regarding the relay outage is to limit, to the extent possible, the duration of a relay package outage for transmission facilities with impacts outside the local area. These relay packages are part of redundant relay schemes and only one of the redundant schemes is removed from service for testing or repair. The review is **not** intended for ISO to approve of the reason for the outage or to facilitate the repair; the purpose of the review is for ISO to remain apprised of the TO/TOP actions that are undertaken to return all facilities to service in a timely manner. A failure by the TO/TOP to remediate the unexpected relay outages may require ISO to implement system operational adjustments, which may include but are **not** limited to:

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- Equipment/facility outage
  - Transmission and/or Generator/DARD
- Reduced transfers
- Load shed

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VIII. TRANSMISSION OUTAGE PRIORITY

When a conflict arises with another transmission outage previously scheduled, the ISO shall attempt to resolve conflicting Long-Term and Short-Term Transmission Outage requests through discussions with the affected LCCs. When discussions **cannot** resolve the conflict, the respective priorities of the Outages shall be established according to the Outage status in the following order (highest to lowest priority):

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1. Unplanned Outages (Emergency or Forced)
2. Long-Term Transmission Outage with Interim Approved Status and the Long-Term Economic Approval flag:
3. Long-Term Transmission Outage with Interim Approved Status
4. Short-Term Outages
5. Opportunity Outage

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<#>Long-Term Transmission Outage with Interim Approval Status and the following flag ...

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<#>Long-Term Economic Approval ...

If the above priorities don't resolve the conflict, the transmission outage that was input earliest shall have priority.

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IX. OUTAGE WORK REPORTS

A. LOCAL CONTROL CENTER TRANSMISSION WORK REPORT

Daily by 1000, each LCC shall forward to ISO and, if appropriate, to the adjacent LCCs a report that includes all equipment listed as Category B Facilities, which does **not** affect Generator/DARD output that is to be worked on during the following day. (The Friday report shall include equipment positioned to be worked on during Saturday, Sunday and Monday. Work on holidays shall be reported on the last regular weekday before the holiday). The report shall include outage times when work is to begin and end.

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Following the Local Control Center Transmission Work Report, other reports from the LCC to ISO and, if appropriate, to the adjacent LCCs shall include any additional work outage for the following day and/or outage work during the following day that is cancelled or postponed.

B. REVIEW OF TRANSMISSION WORK

Once work has been approved and Control Center reports have been completed, both ISO and the LCCs shall operate according to the published outage application times. The party initiating the change shall communicate any changes, for any reason. All affected parties shall be notified of the change in work times.

On the night shift prior to the day the work is scheduled, ISO and the LCCs shall discuss the day's upcoming work to ensure that all parties are up to date on work times for switching and equipment work

Each LCC shall confirm final approval of the transmission outage application by ISO Security Operator before switching begins. ISO shall be informed immediately when equipment is taken out of service and/or restored to service.

X. ANNUAL REPORT ON OUTAGE PROCESSING

ISO in coordination with the LCCs and Participating Transmission Owners shall prepare and issue an annual report on transmission outages and coordination. The report shall assess accuracy of inputs and calculation of congestion cost savings. The long-term impacts of ISO, LCC and Participating Transmission Owner changes to outages shall be assessed and identify potential opportunities to further minimize congestion costs identified.

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OP-3 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.)

Rev. No.	Date	Reason
Rev 1	4/5/2002	
Rev 2	02/01/05	Updated to conform to RTO
Rev 3	05/06/05	Update for initiation of VELCO Local Control Center
Rev 4	02/03/06	Updated to conform to FERC changes of MR 1 Attachment G, and added information to clarify the transmission outage process
Rev 5	10/01/06	Updated for ASM Phase 2
Rev 6	02/08/07	Revised Opportunity Outage criteria
Rev 6.1*	06/17/08	Annual Review by Procedure Owner. Clarification and consistency of terminology Use of approved M-35 acronyms, e.g., LCC for Local Control Center, DARD for Dispatchable Asset Related Demand, etc. Defined acronyms for frequently used terms: e.g., CA/BA for Control Area/Balancing Authority, etc| Minor reformatting changes Corrected References for NSTAR becoming an LCC Corrected NBSO instead of NB Power *Revision 6.1 is an exception to the normal revision history numbering protocol. Changes previously approved as Revision 7 by the Participants Committee will be released as the effective version at a later date.
Rev 7	12/15/08	Revised procedure for Long-Term Transmission Outage process changes and clarification of outage terminology. (Added changes approved by RC-MC voting completed on 02/19/08 meeting)
Rev 8	12/11/09	Section V.B. Minimum Advanced Notice Time-Response Time for Long-Term Transmission Outages Added language to exempt business days that occur during the blackout period from the minimum response time. Section V.C. Long Term Transmission Outage review Blackout Period This is a new section that defines the blackout periods when transmission outage requests will not be reviewed to accommodate FCM related reliability reviews.
Rev 9	12/01/10	Biennial review by procedure owner; Global: format changes; Arranged Definitions section to be alphabetical; Replaced current definitions of Category "A", Category "B" and Local Area Facilities with TOA (Transmission Operating Agreement) terminology; Replaced Control Area/Balancing Authority Area (CA/BAA) with Reliability Coordinator Area/Balancing Authority Area, replaced Control Area/Balancing Authority (CA/BA) with Reliability Coordinator/Balancing Authority and defined and used new acronyms RCA/BAA and RC/BA
Rev 10	06/10/11	Retire Appendices B and C remove references to Appendices B and C in text
Rev 11	11/18/11	Delete Section X, modified Long Term Transmission Outage submission timetable
Rev 12	11/13/13	Biennial review by procedure owner; Global, minor format, grammar , punctuation, etc., changes per current practices and management expectations; Added new Section VII.C providing direction for unexpected relay outages; Modified title for Section IV.5 to delete "Critical"; Modified Section VII.C; Added MLCC 15 to References Section
Rev 13	01/30/15	Modified MTE definition, updated OP-5 title, minor editorial corrections;
Rev 13.1	09/16/15	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision per SOP-RTMKTS.0201.0010 Section 5,6 and sub-Section 5.6.1; ;

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Rev. No.	Date	Reason
Rev 14	Draft	Deleted MTO Flag and associated references; Removed Long Term (ten day) transmission outage review period; Added clarifying language for processes and definitions (promoted the consideration of all transmission outages in the FTR monthly auctions, defined "recall time, implemented and completed", provided clarification to economic outages for MTE, removed the term "relay" and replaced with "communicate"; Deleted language describing activity and processes covered in Manual M-06

Deleted: 13.1

Deleted: September 16, 2015

Chief of Staff, Larry D. Gasteiger

Larry D. Gasteiger is the Chief of Staff. He previously served as the Acting Director of the Office of Enforcement from August 2014 to April 2015 after having served as the Deputy Director from 2009 to 2014. Before he joined the Office of Enforcement, Mr. Gasteiger was the Director of the Division of Tariffs and Market Development - East in the Office of Energy Market Regulation. Prior to that, he held several other positions at the Commission, including Deputy Associate General Counsel, Legal Advisor to Chairman Joseph T. Kelliher, and attorney in the Solicitor's Office. Before joining FERC in 1997, Mr. Gasteiger was an attorney in the General Counsel's Office at the Commodity Futures Trading Commission, and from 1989 to 1991 he served as a law clerk for the Honorable Edwin M. Kosik in the United States District Court for the Middle District of Pennsylvania.

Mr. Gasteiger is a graduate of the University of Pennsylvania and the Dickinson School of Law. He resides in Fairfax, Virginia with his wife and three children.

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Washington, DC 20426

Summary of ISO New England Board and Committee Meetings

December 4, 2015 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Nominating and Governance Committee, and the Board of Directors met in Boston on November 5. In addition, the Markets Committee met by teleconference on November 19.

The Audit and Finance Committee received an update on internal audit activities including follow-up items related to internal reviews and the oversight of external audits. There was a general discussion on the role of cyber security and overall personnel needs in the security area, and the goal of balancing between headcount and addressing material vulnerabilities. The Committee then met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2015 SOC 1/SSAE 16 review and resultant unqualified opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee met with the auditors in executive session. Next, the Committee met with a representative from Meyers Brothers Kalicka, the external auditors of the Company's pension, health & welfare plans. The Committee discussed the limited scope audits performed in which there were no adverse findings. The Committee then reviewed compliance issues, including the results of the annual process pursuant to which employees certify that they are in compliance with the Code of Conduct. The Committee was provided with a report on cyber security, and discussed current budget performance along with an update on interest rates. The Committee also approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Finally, the Committee agreed to recommend that the Board approve a minor change to the Committee's charter.

The Compensation and Human Resources Committee convened and reviewed the goal setting, assessment and compensation schedule for 2016. The Committee was also provided with an overview of employee benefits and considered its annual calendar for 2016.

The Nominating and Governance Committee met and received an update on activities of the Joint Nominating Committee, and generally discussed opportunities for stakeholder interaction and director education. The Committee also discussed the use of peer and self-evaluations, and considered its annual calendar for 2016.

The Board of Directors received reports from the standing committees, including the committees' risk assessments for the key risks that fall within the scope of each committee's oversight. The Board also approved the 2015 Regional System Plan as recommended by the System Planning and Reliability Committee. The Board received an annual Forward Capacity Market Pre-Auction update and a summary of resource qualification. Next, the Board conducted its annual risk management review and discussed the various topics related to potential risks, including the primary risks that the New England wholesale electricity market faces. Finally, the Board prepared for the upcoming sector meetings with NEPOOL and reviewed topics proposed by stakeholders for discussion.

The Markets Committee met on November 19 by teleconference and received reports from the internal and external market monitors, and discussed factors affecting the convergence of day-ahead and real-time prices. The Committee received a report on the Coordinated Transaction Scheduling project, which is currently on schedule for implementation in December and final testing underway with the NYISO. The Committee also received an update on the proposed market rule changes to address the potential of uneconomic retirement of capacity resources and stakeholder discussions to date.

DECEMBER 4, 2015 | BOSTON, MA

NEPOOL Participants Committee Report

December 2015

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $245M over the period, down $130M from October 2015 and down $254M from November 2014
  - November natural gas prices over the period were 7.4% lower than October 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 16.5% lower than October 2015 averages
  - Average November 2015 natural gas prices and RT Hub LMPs over the period were down 45% and 39%, respectively, from November 2014 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 98.3% during November, down from 100% during October

All data through November 24 (RT NCPC through November 22) except where otherwise noted.

Underlying natural gas data furnished by:

ice Global markets in clear view

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled $10.0M, down $711K from October and up $2.9M from November 2014
    - November NCPC payments attributable to the RT evaluation of non fast-start unit that cleared DA totaled $5.0M
  - First Contingency payments totaled $4.6M, down $574K from October
    - $4.3M paid to internal resources, up $706K from October
      - $813K charged to DALO, $3.5M to RT Deviations
    - $311K paid to resources at external locations, down $1.3M from October
      - $214K charged to DALO at external locations, $97K to RT Deviations
  - Second Contingency payments totaled $4.1M, down $1.0M from the October total of $5.1M
  - Voltage payments were $1.3M, up $904K from October
  - NCPC payments over the period as percent of Energy Market value were 4.1%

Highlights, cont.

- ISO Board of Directors approved the 2015 Regional System Plan on November 5
- Changes to the RSP process are being proposed such that the next RSP would be issued in 2017
- FERC filings made on November 10 regarding qualification of resources and regional/zonal requirements for the tenth Forward Capacity Auction
- 2015 economic planning studies are underway. All three study requests focus on the impacts of wind integration. Study updates to be presented at the December 14 Planning Advisory Committee (PAC) meeting
- Technical session on the generation queue and overlapping impact test analysis to be presented at the December 15 PAC meeting
- Results of the reliability review for the Pilgrim Non-Price Retirement Request to be presented at the December 16 Reliability Committee meeting

Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014)
  - Less than 4 MW of resources are non-commercial at this time
- CCP #5 (2014-2015)
  - Less than 17 MW of resources are non-commercial at this time
- CCP #6 (2015-2016)
  - Less than 123 MW of resources are non-commercial at this time
- CCP #7 (2016-2017)
  - Updated Installed Capacity Requirement (ICR) will be filed with FERC no later than December 1, 2015
  - Third bilateral transaction window will be December 1-7, 2015
  - Third reconfiguration auction will be March 1-3, 2016
    - Based on results of the second reconfiguration auction, entering the CCP, the Transmission Security Analysis margin for NEMA/Boston will be about 356 MW short. ISO Operations is working with the Local Control Centers to address this deficiency.

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #8 (2017-2018)
  - Updated ICR will be filed with FERC no later than December 1, 2015
  - Second bilateral transaction window will be May 2-6, 2016
  - Second reconfiguration auction will be August 1-3, 2016
- CCP #9 (2018-2019)
  - Updated ICR will be filed with FERC no later than December 1, 2015
  - First bilateral transaction window will be April 1-7, 2016
  - First reconfiguration auction will be June 1-3, 2016

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #10 (2019-2020)
  - Non-price retirement window closed on October 12. A total of approximately 728 MW of retirements were received including a full retirement request of 677 MW from Pilgrim
    - Only Pilgrim is yet to be reviewed for reliability. Results to be presented to the RC at their December 16 meeting.
  - Approximately 62 MW of generation and demand resources will receive the Renewable Technology Exemption
  - Both the Qualification and Requirements (ICR and Local Sourcing Requirement) FERC Filings were made on November 10
  - Forward Capacity Auction to commence on February 8, 2016
- CCP #11 (2021-2022)
  - Preparations are underway for existing and new resource qualification training which will incorporate timeline changes and new rules (associated with the Retirement Reforms Project and subject to FERC approval)

FERC Order 1000

- ISO, PJM, and NYISO are developing joint interregional planning procedures
- IPSAC meeting has been scheduled for December 14 to discuss interregional needs and other issues

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for week beginning January 9, 2016

2015/16 Winter Reliability Program (As of October 1)

- **Oil Program**
  - By the Oct. 1 deadline, 81 Units submitted intent to provide 4.464 million barrels
  - Based upon assets participating in program total eligible oil is anticipated to be 2.965 million barrels
  - Total oil program cost exposure is anticipated to be $38.25M (@$12.90/barrel)
- **LNG Program**
  - By the Oct. 1 deadline, 8 Units submitted intent to provide at least 1.42 million MMBTU
  - Based upon asset submissions, and capping submissions to permissible asset thresholds total eligible LNG is 1.278 million MMBTU
  - Total LNG program cost exposure is anticipated to be $2.75M (@$2.15/MMBTU)
- **DR Program**
  - By the Oct. 1 deadline, 7 Assets submitted (6 accepted by ISO) an intent to provide at least 26.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $132K

2015/16 Winter Reliability Program (As of December 1)

- **Oil Program**
  - As of December 1st, confirmation of participation from 81 units for a total of 4.519 million barrels of oil
  - 2.963 million barrels of the total inventory on December 1 are eligible for compensation per the winter program rules
  - Total oil program cost exposure is expected to be $38.22M (@$12.90/barrel)
- **LNG Program**
  - As of December 1st, confirmation of participation from 8 units, representing 1.278 MMBTU
  - Total LNG program cost exposure is expected to be $2.75M (@$2.15/MMBTU)
- **DR Program**
  - As of December 1st, confirmation of participation from 6 assets providing 26.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $132K

Winter Reliability Program Update

- Dual Fuel Commissioning Program
  - Participation:
    - 6 Units submitted intent to commission Dual Fuel Capability
      - 4 units for 2014/15 (1,039 MW)
      - 2 units for 2015/16 (735 MW)
    - Total additional winter seasonal claimed capability represented: 1,774 MW
  - Dual Fuel Commissioning Activity and related NCPC:
    - Units commissioned (as of Nov. 30): 5 successful, 1 outstanding
    - Total NCPC Commissioning Cap: $5.7M
      - 2014/15: $3.56M
      - 2015/16: $2.19M
    - NCPC incurred (as of Nov. 22): $1.1M*
    - Remaining Commissioning Cap for 2015/16: $0.8M

***Subject to increase as NCPC data over the last 8 days of November is finalized**

CTS Background

- CTS will improve the market efficiency of external transactions between the NY and NE regions
- CTS Goals and Benefits:
  - **Reduces Latency**
    - Tie scheduling interval will be every 15 minutes
    - Shared clearing process will finalize a schedule approximately 20 minutes ahead of the interval start
  - **Minimize non-economic clearing**
    - ISOs will use a shared clearing process using forecasted price and system data from both ISOs
    - Participants provide a single transaction at a minimum price spread they are willing to accept
- Note that under certain reserve deficiency conditions (for example; shortage of ten minute operating reserves), each Control Area will take the necessary actions to protect reliability

CTS Project Status

- Generator Control Application (GCA), which features a look-ahead commitment model, was implemented on November 9
  - This application was a pre-requisite for CTS implementation
- CTS will be implemented effective December 15th
- FERC notice of December 15th effective date was filed on December 2nd
- Extensive joint testing with NYISO successfully completed
- Access to NYISO's Joint Energy Scheduling System (JESS) for bidding opened to ISO-NE stakeholders on December 2nd
- ISO will monitor the performance of the CTS function and report its observations to stakeholders in Q1 2016

NERC GRIDEX III

- On November 18 and 19, ISO New England and many New England Utilities participated in GridEx III, a North American wide electrical grid exercise that was designed for electric utilities to exercise their response to simulated coordinated cyber and physical security threats and incidents
- GridEx III was purely an exercise and the simulated scenarios did not impact actual bulk power system or wholesale market operations.
- ISO New England conducted the entire exercise using the Training Simulator at its Backup Control Center

NERC GRIDEX III, cont.

- ISO New England and many New England Utilities were full participants in GridEx III
  - As full participants, exercise scenarios were developed specifically for New England's bulk power system and required a resource-intensive response by ISO New England and the New England Utilities that participated
- The GridEx exercise simulated physical and cyber-attacks on a number of bulk electric system facilities across New England and played out a number of aggressive and impactful scenarios disrupting both the flow of data and physical damage to the New England power grid
- It provided an excellent opportunity for New England to test its ability to respond to attacks on the grid

NERC GRIDEX III, cont.

- We are in the process of evaluating the exercise response across the ISO, New England Utilities, NPCC and NERC
- ISO and participating utilities followed established operating and security procedures to maintain reliable grid operations during the two full days of simulated grid attacks
- As we evaluate our (and regional) response, we expect to find many opportunities for improvement, which will further strengthen our ability to respond to these events in the future
- We expect that NERC will publish a full report on this exercise in Q2 2016

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature –Above Normal (+3.1°) Max: 76.0°, Min: 28.0° Precipitation 2.07" – Below Normal Normal 3.98"	Hartford	Temperature – Above Normal (+3.7°) Max: 76.0°, Min: 19.0° Precipitation 2.20" - Below Normal Normal 4.06"

Peak Load:	17,410 MW	November 23, 2015	18:00 (ending)

M/LCC 2: 11/2/2015	Transmission Constraints	Declared: 12:15 Cancelled: 21:00
OP 4 : None		
NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
11/12/2015	PJM	1,280
11/13/2015	IESO	850

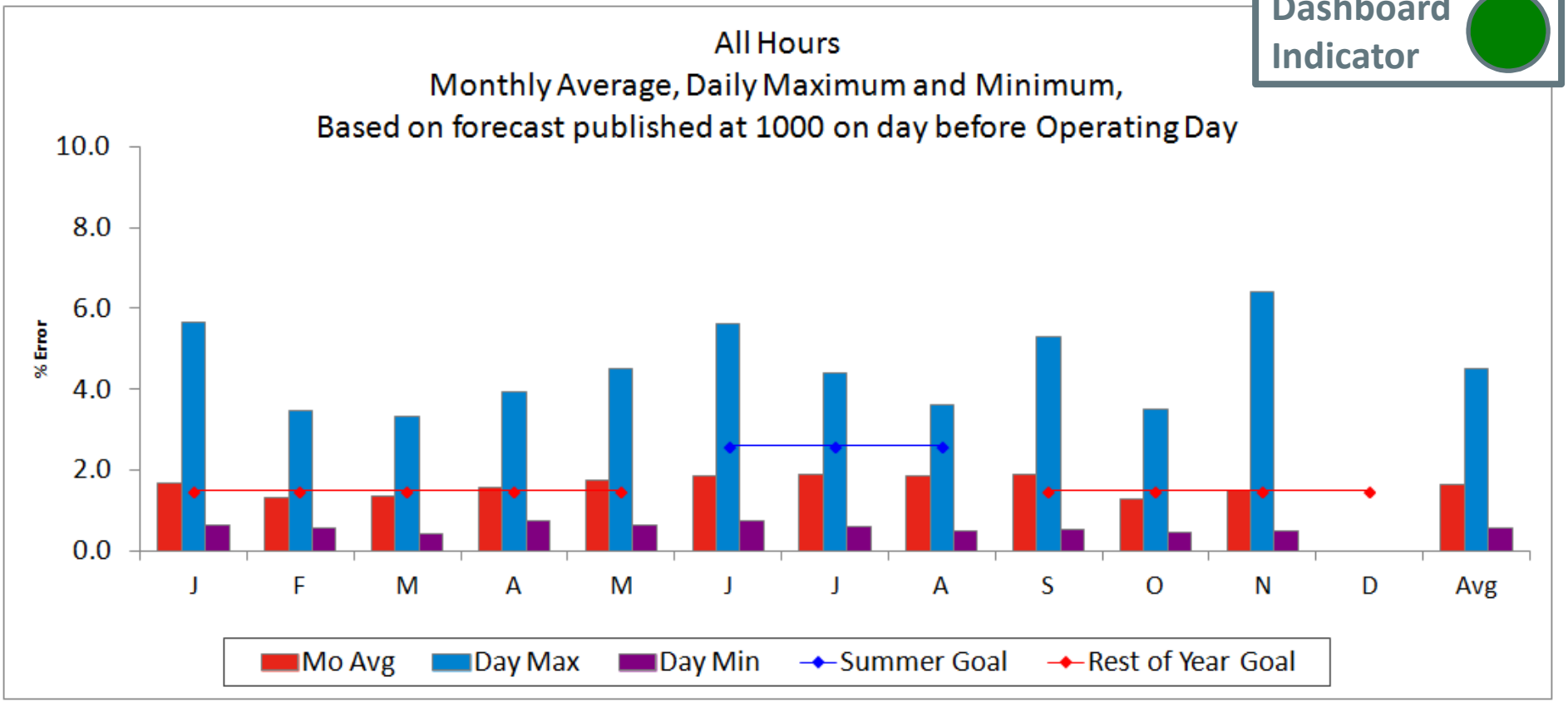
System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	11/22/15, 23:00 – 11/23/15 06:00	No Actions Necessary

2015 System Operations - Load Forecast Accuracy

Dashboard Indicator

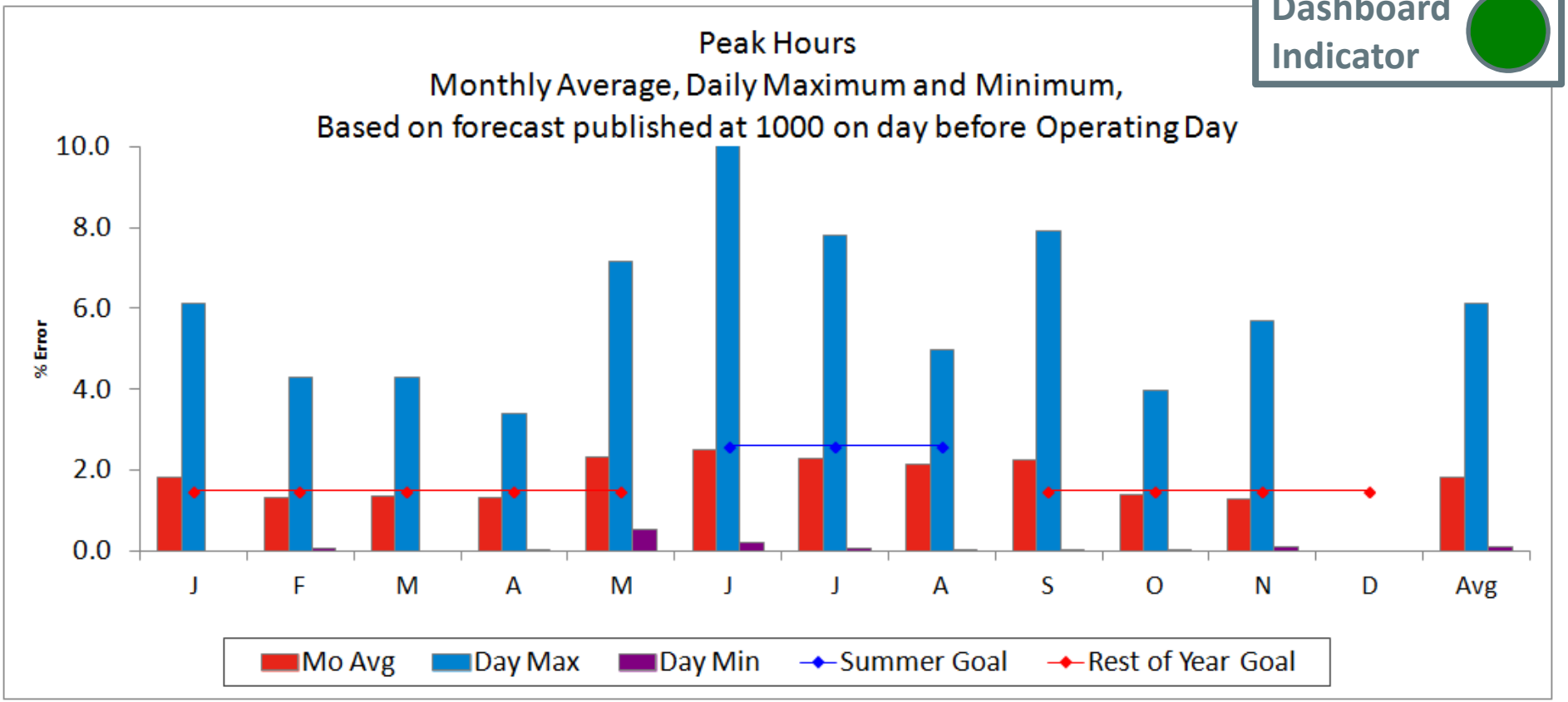


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.70	1.31	1.37	1.59	1.76	1.88	1.91	1.88	1.90	1.30	1.49		1.65
Day Max	5.66	3.47	3.35	3.93	4.53	5.64	4.41	3.63	5.31	3.51	6.40		4.53
Day Min	0.65	0.57	0.44	0.74	0.63	0.75	0.60	0.51	0.53	0.47	0.50		0.58
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.70	1.31	1.37	1.59	1.76				1.90	1.30	1.49		1.55
Summer Actual						1.88	1.91	1.88					1.89

Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2015 System Operations - Load Forecast Accuracy cont.

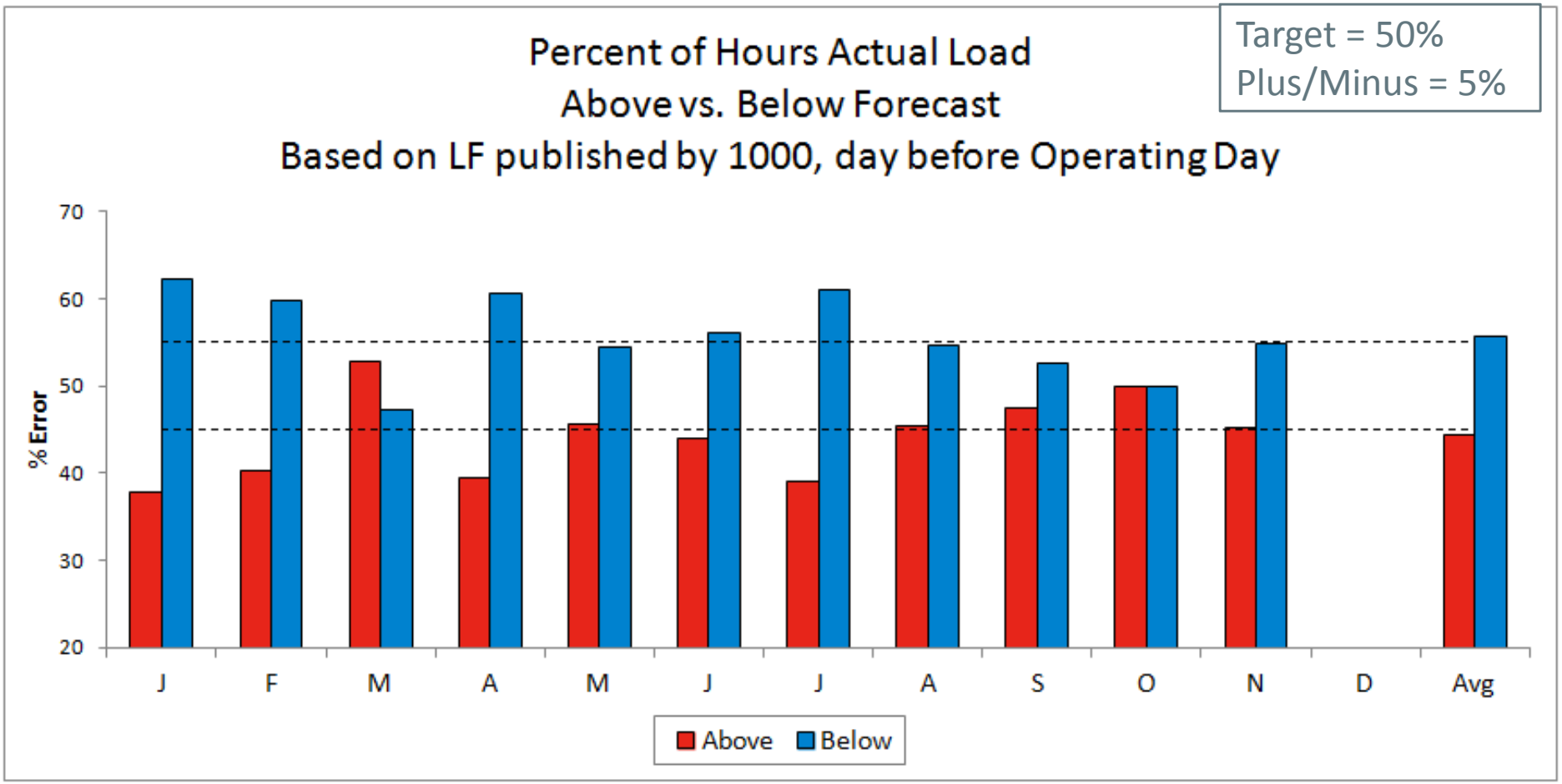
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.84	1.32	1.36	1.32	2.34	2.52	2.28	2.16	2.26	1.38	1.30		1.83
Day Max	6.13	4.31	4.31	3.40	7.15	11.57	7.80	4.97	7.91	3.96	5.68		6.11
Day Min	0.00	0.08	0.00	0.03	0.53	0.22	0.06	0.01	0.03	0.03	0.09		0.10
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.84	1.32	1.36	1.32	2.34				2.26	1.38	1.30		1.64
Summer Actual						2.52	2.28	2.16					2.32

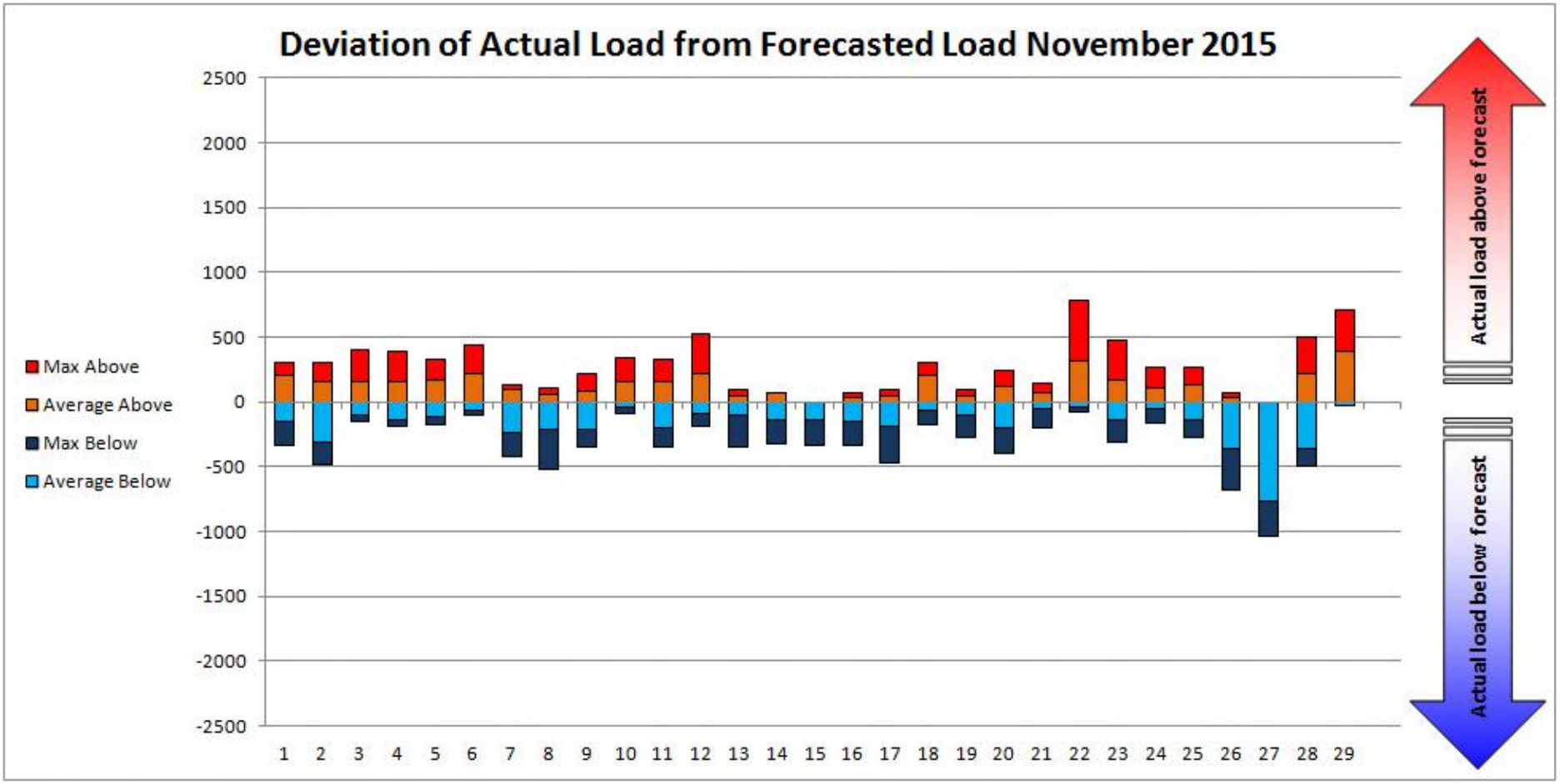
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2015 System Operations - Load Forecast Accuracy cont.

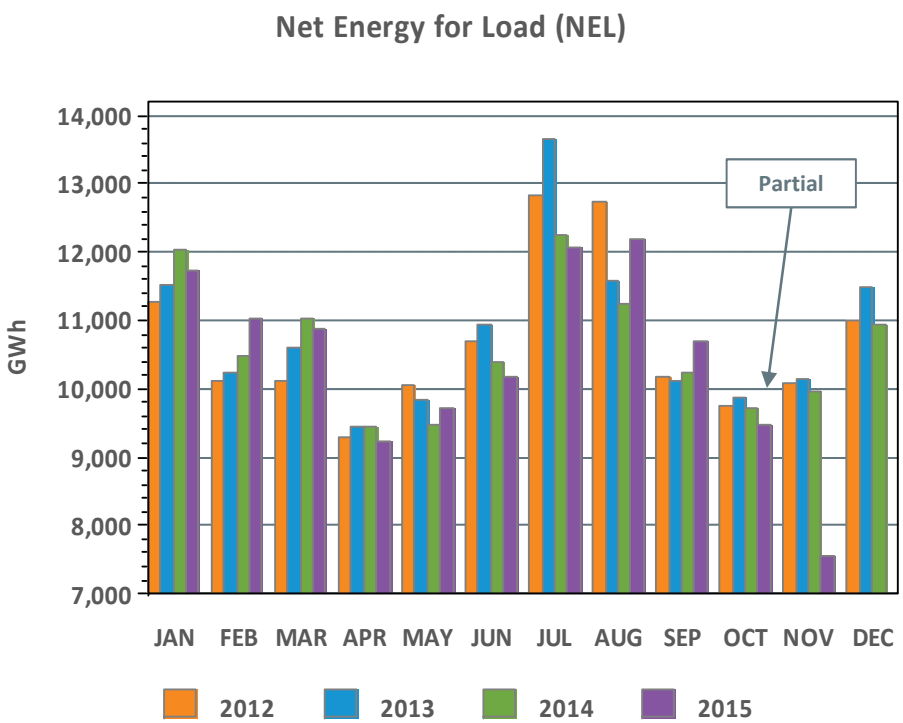


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	37.8	40.2	52.8	39.4	45.6	43.9	39	45.4	47.5	50	45.2		44
Below %	62.2	59.8	47.2	60.6	54.4	56.1	61	54.6	52.5	50	54.8		56
Avg Above	143.4	147	169.7	130.2	215.1	158.9	185.3	201	230.6	127.4	128.1		167
Avg Below	-235.8	-208.2	-146.1	-179.5	-157.4	-212.7	-247.3	-243.8	-192.7	-120.0	-163.7		-191
Avg All	-81	-57	17	-49	34	-55	-70	-39	41	4	-38		-26

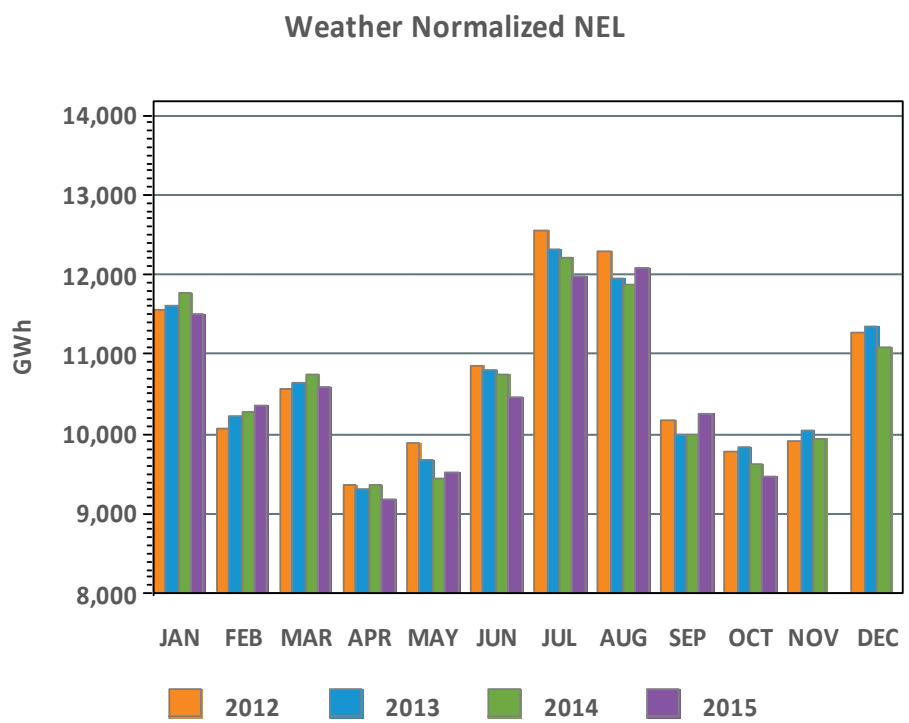
2015 System Operations - Load Forecast Accuracy cont.



Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



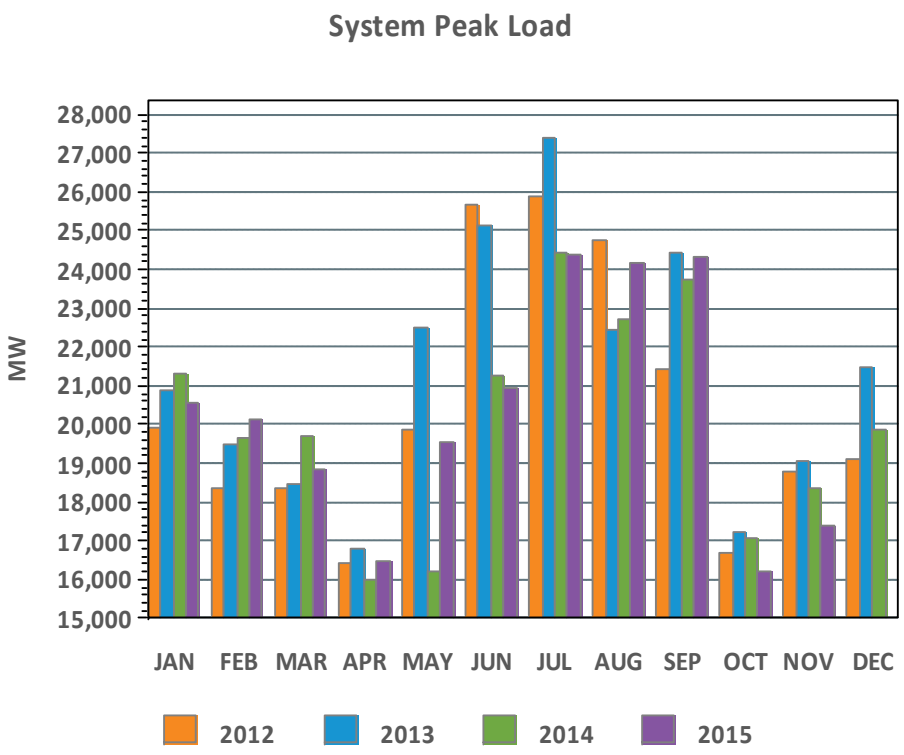
Ann Tot (TWh): 128.1 129.4 127.2 114.7

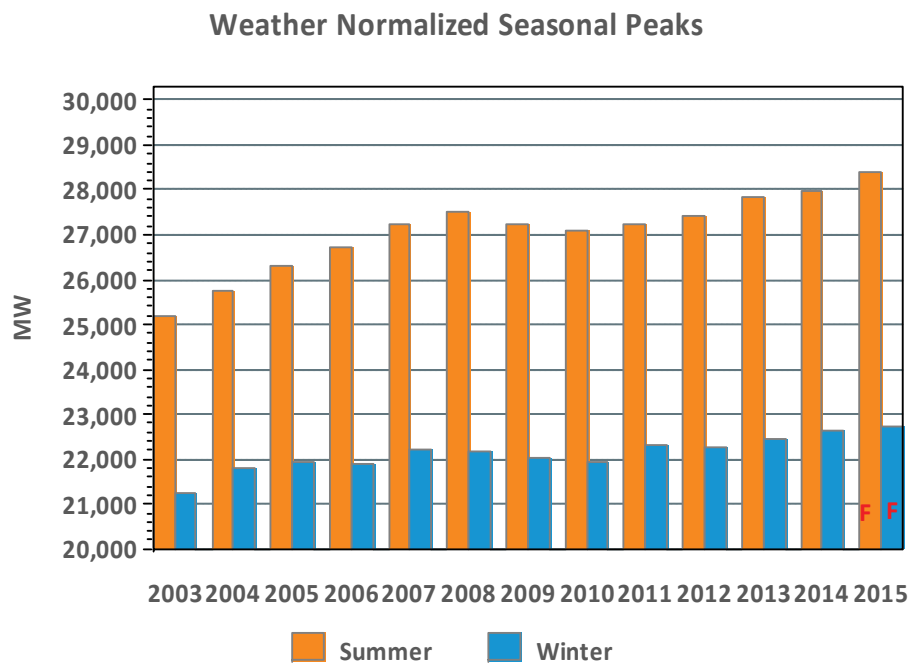


Ann Tot (TWh): 128.2 127.8 127.1 105.4

NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
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



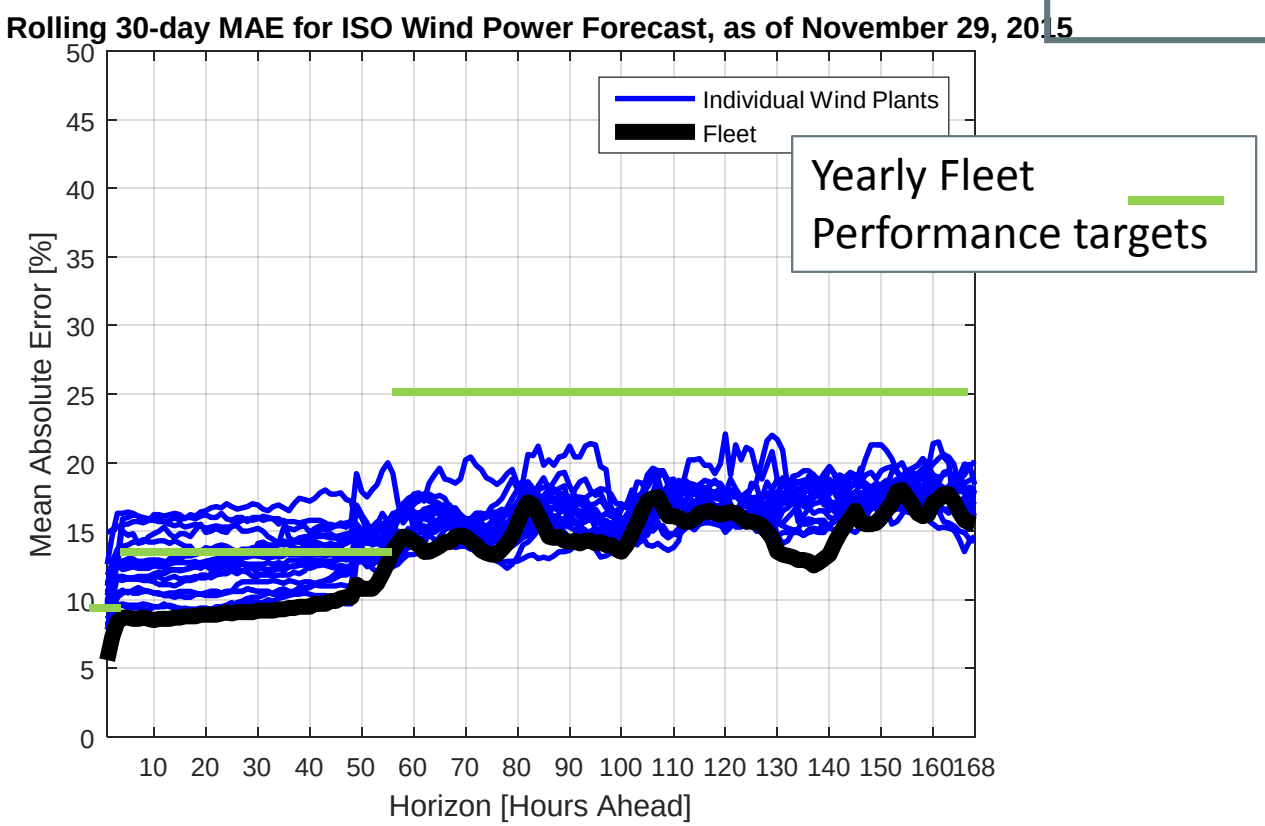


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "gross forecast"

Wind Power Forecast Error Statistics: MAE

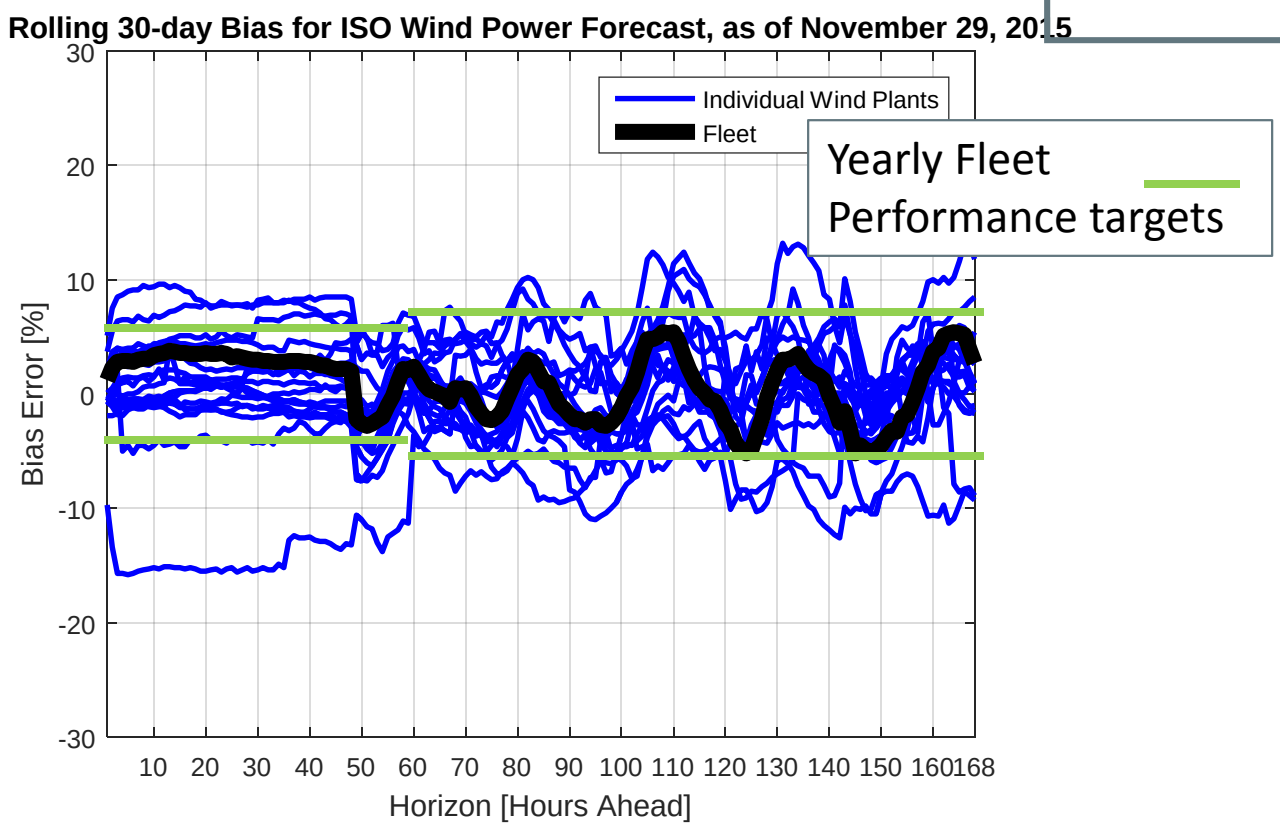
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and MAE continues to be well within the yearly performance targets specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

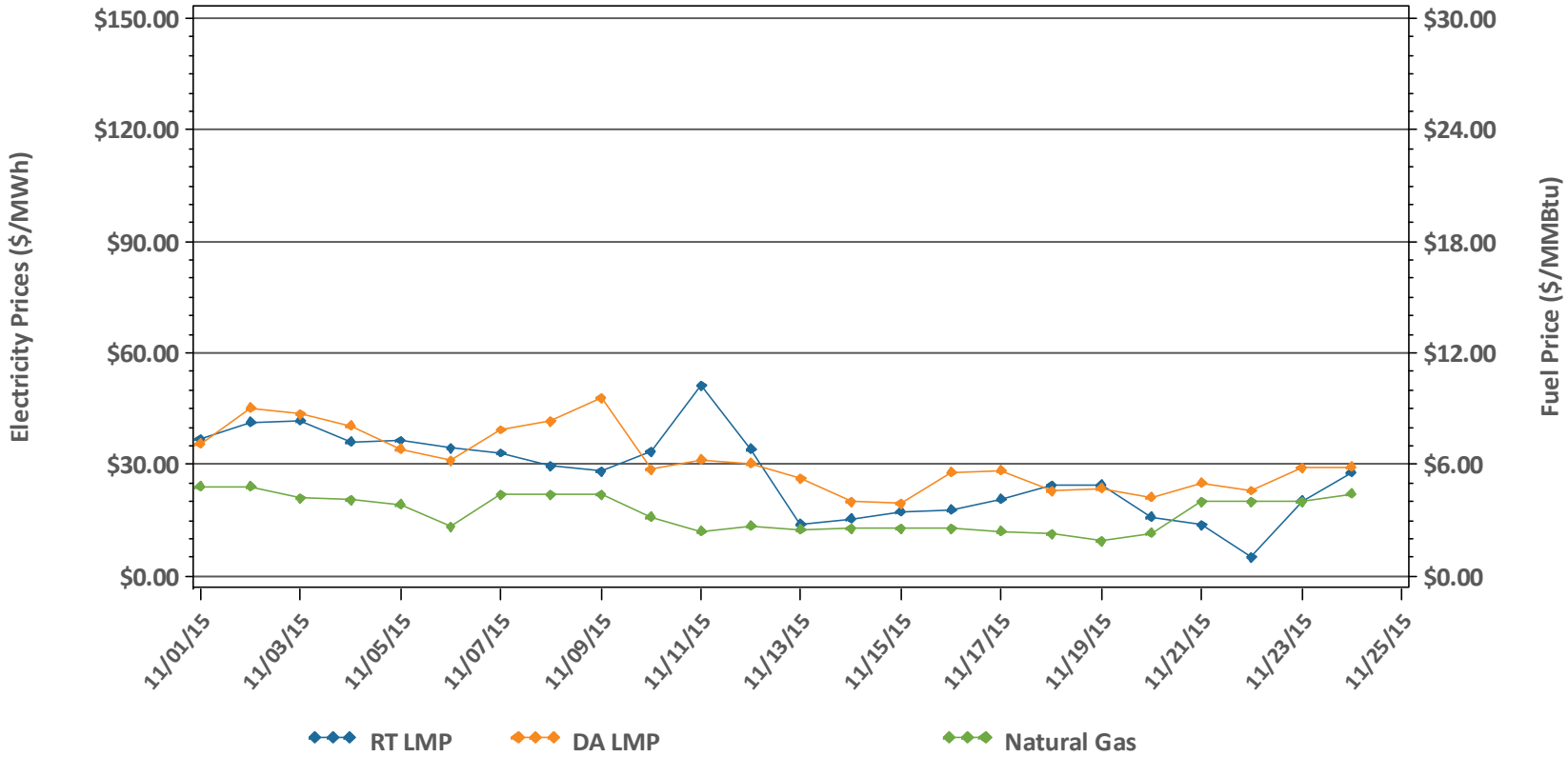
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and October's monthly values are mostly within yearly performance targets specified in the forecast RFP.

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-24, 2015

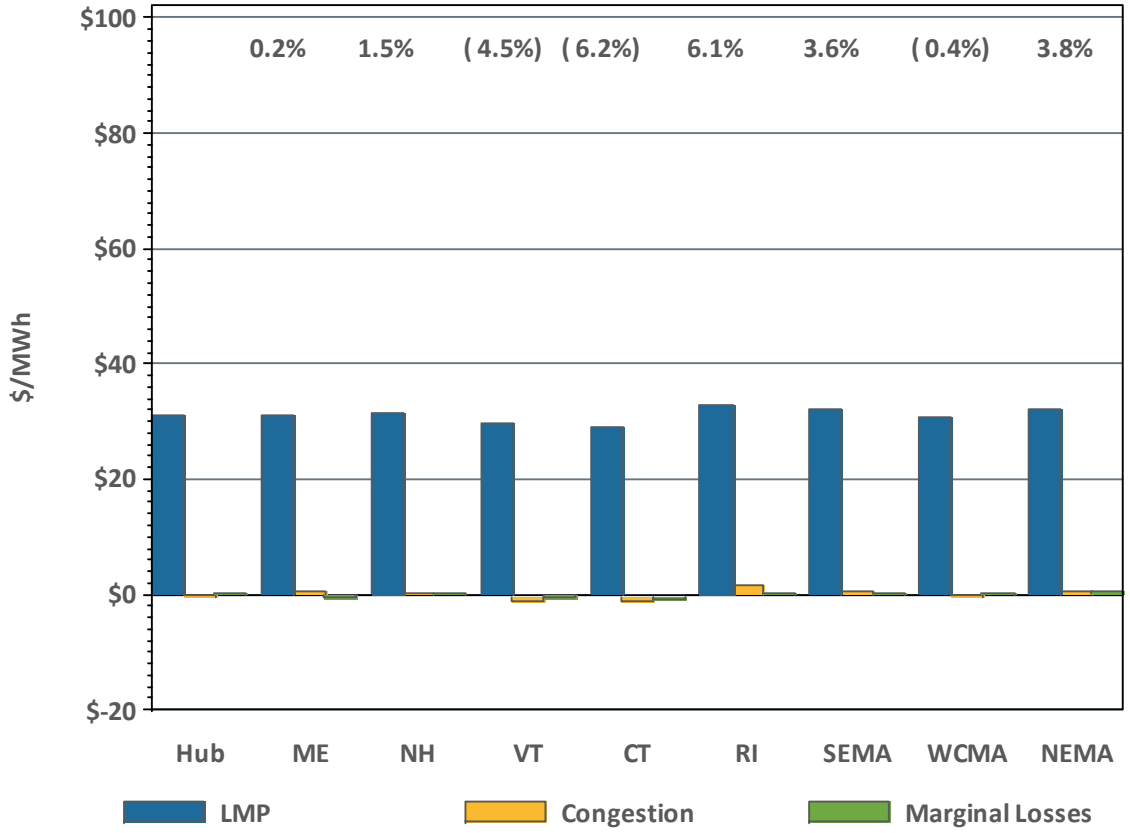


Underlying natural gas data furnished by:

ICE Global markets in clear view

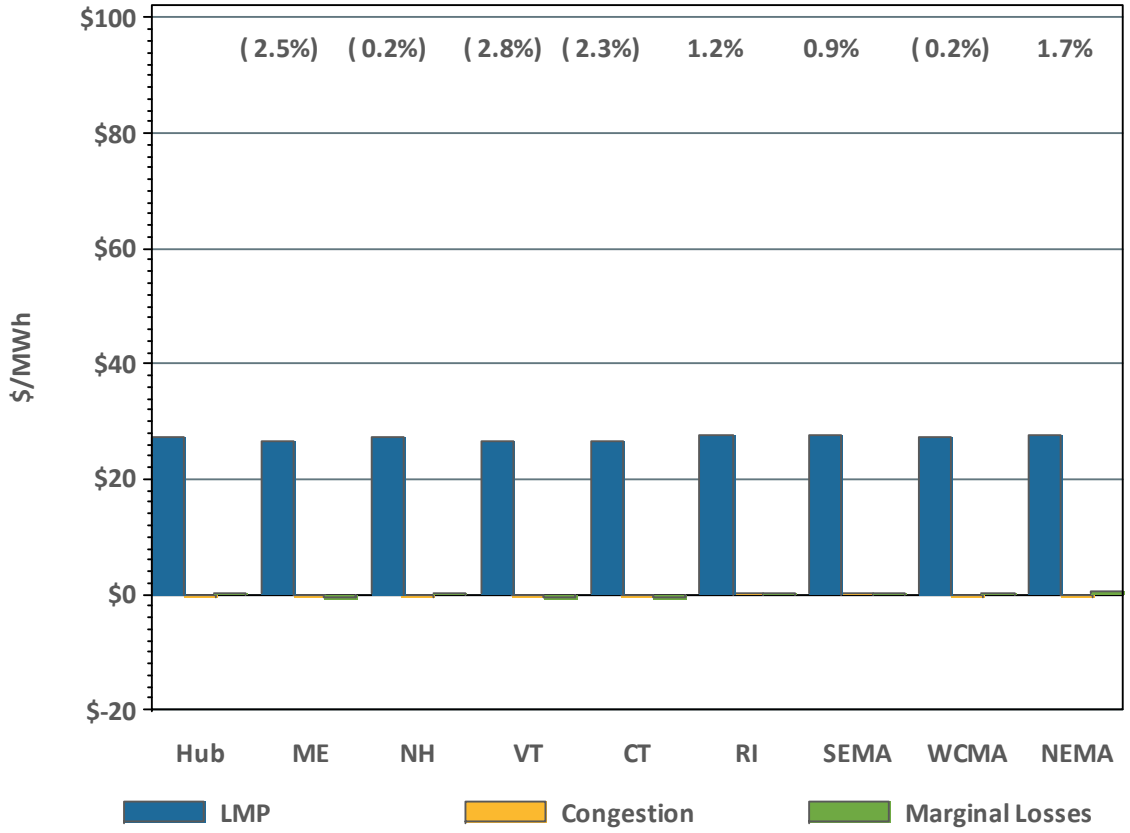
Average price difference over this period (DA-RT): $3.82
Average price difference over this period ABS(DA-RT): $6.98
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2015



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

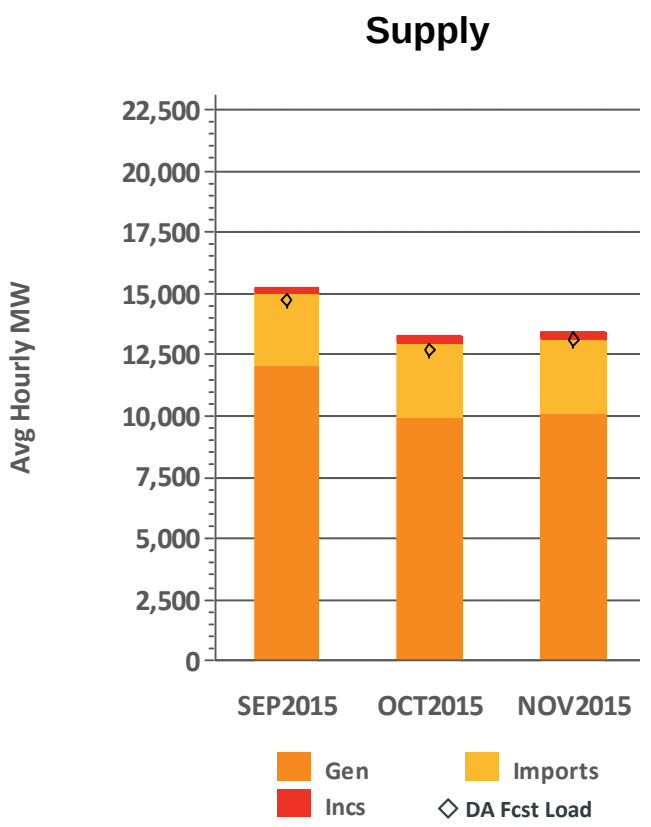
RT LMPs Average by Zone & Hub, November 2015



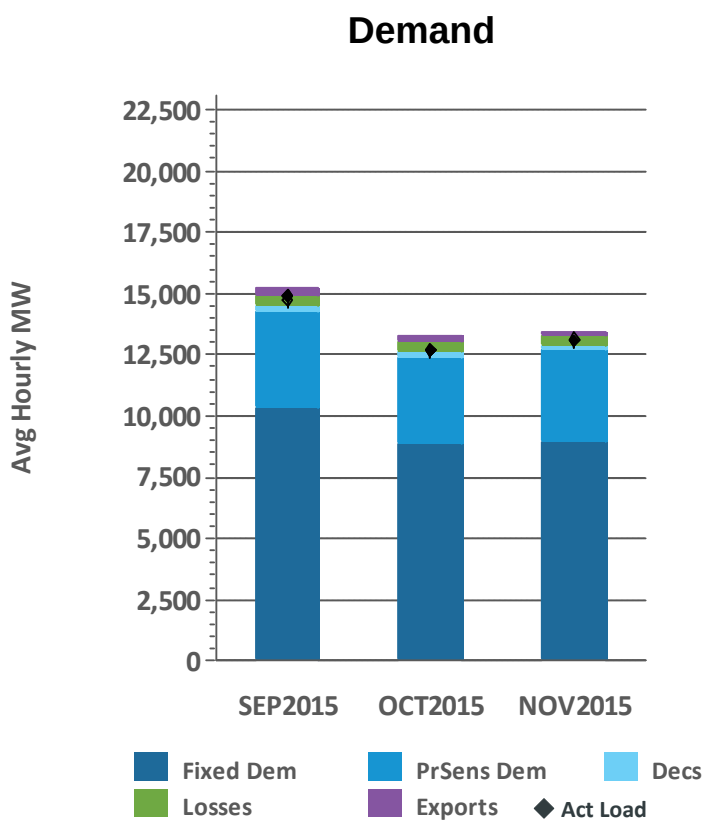
Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

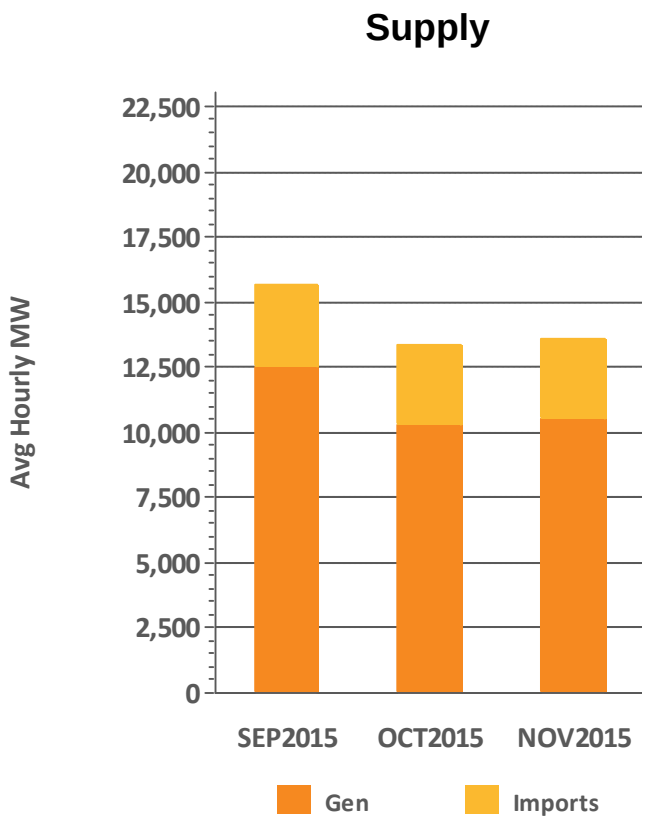


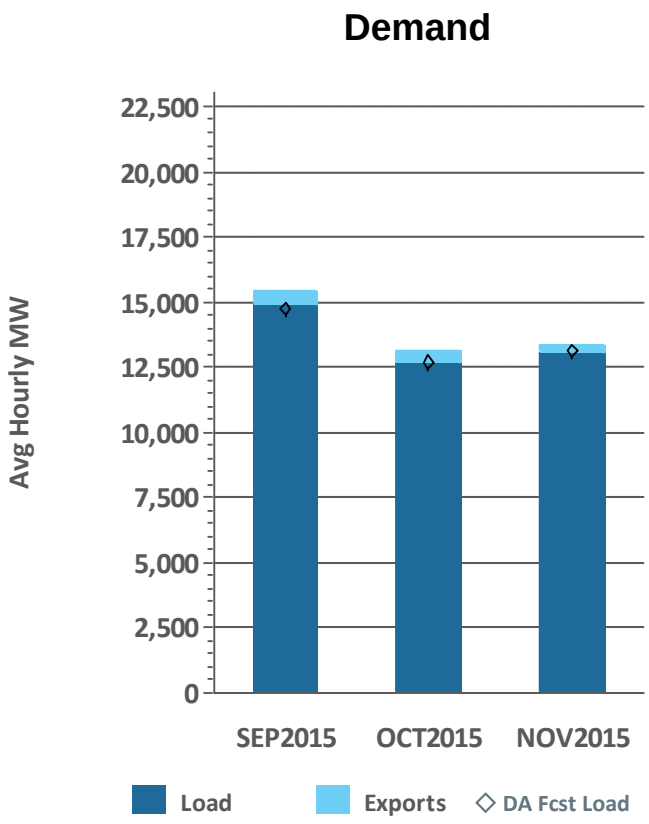
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



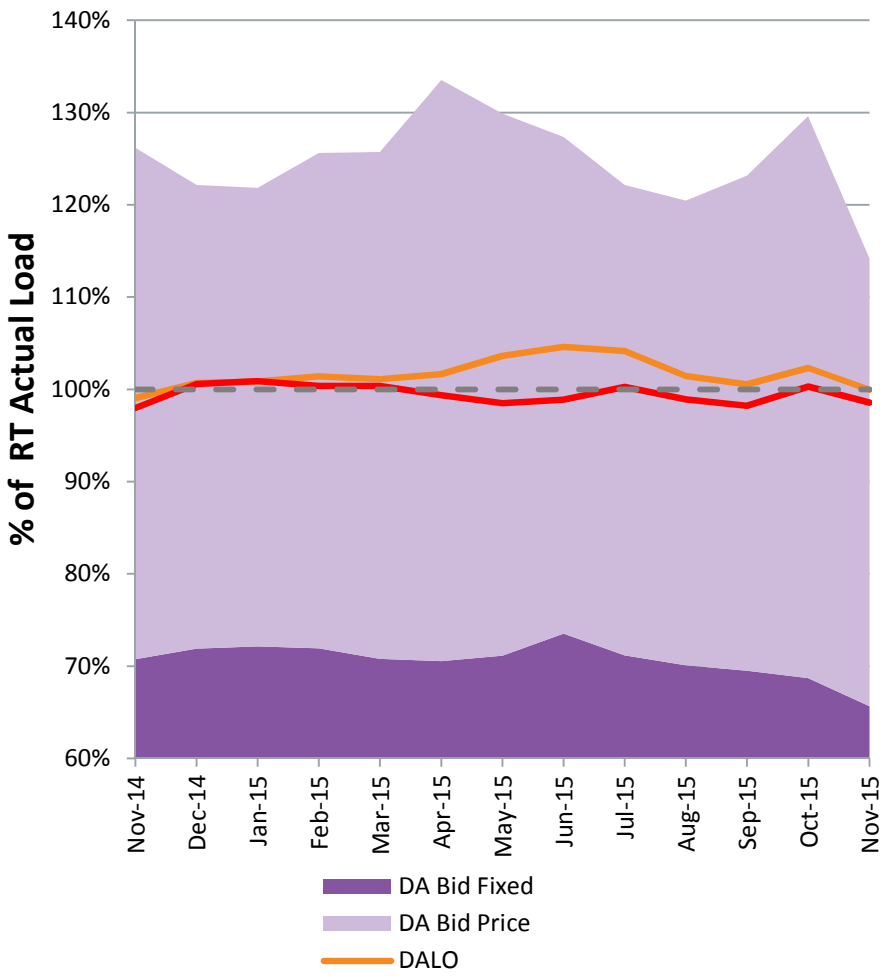
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

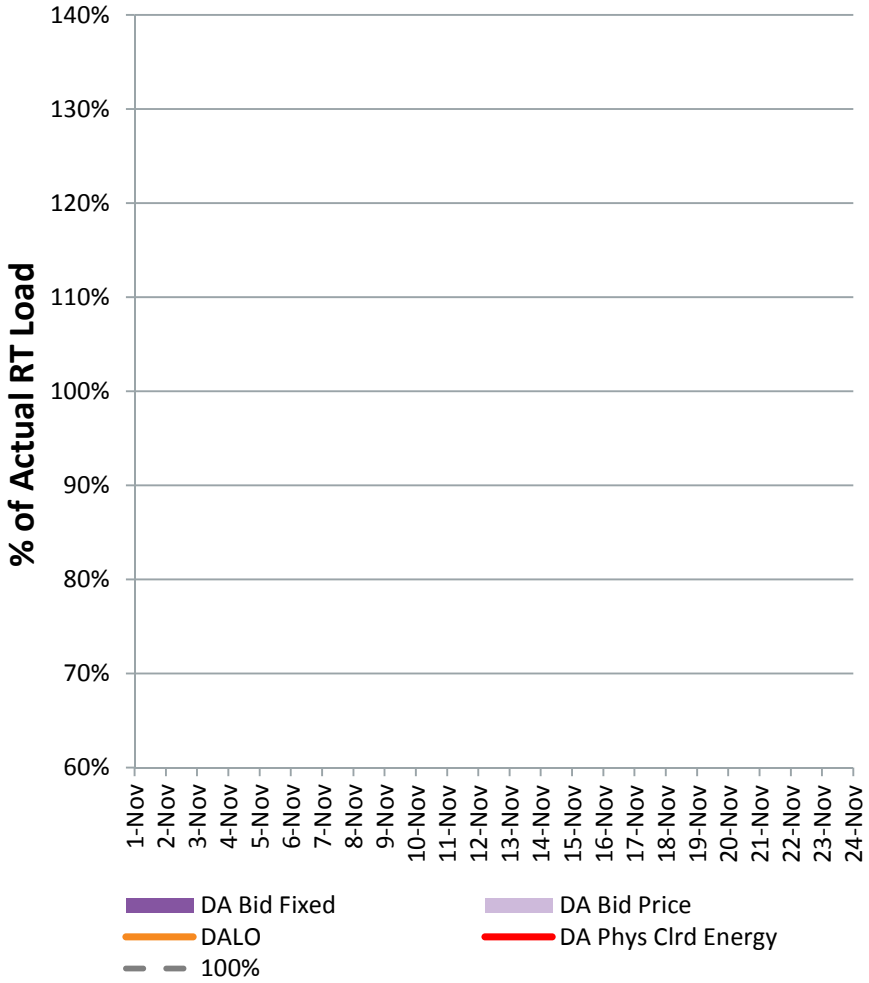
Components of RT Supply and Demand – Last Three Months





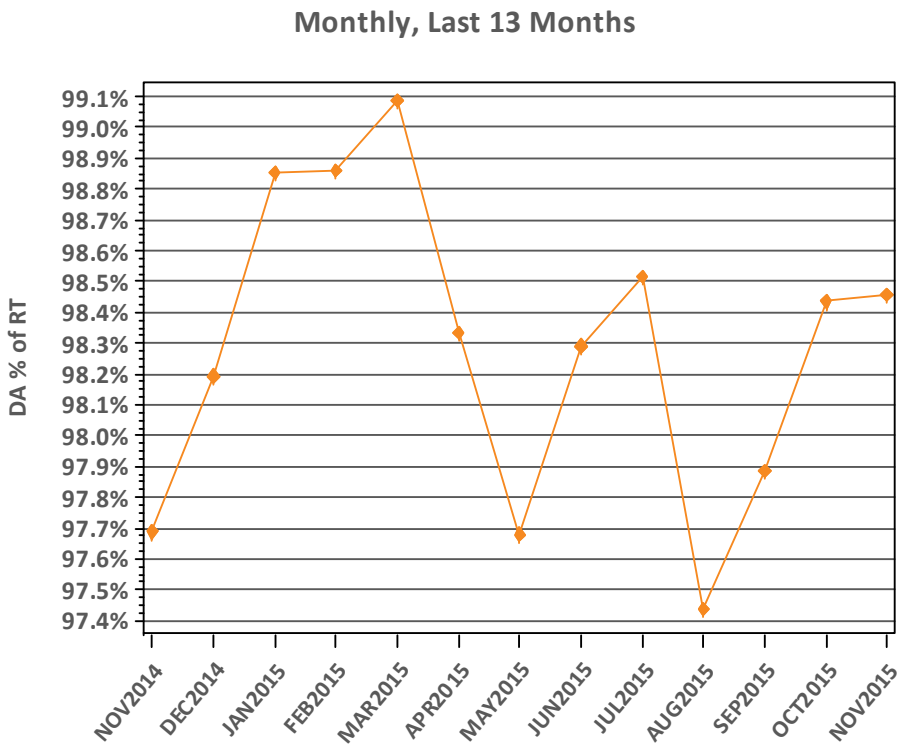
DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily

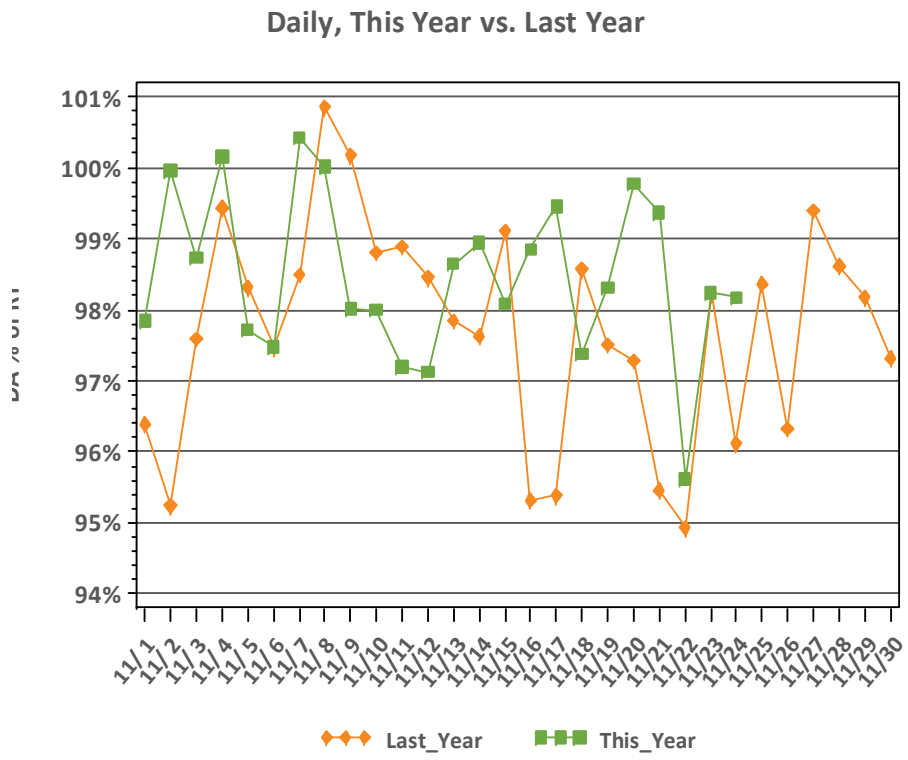




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

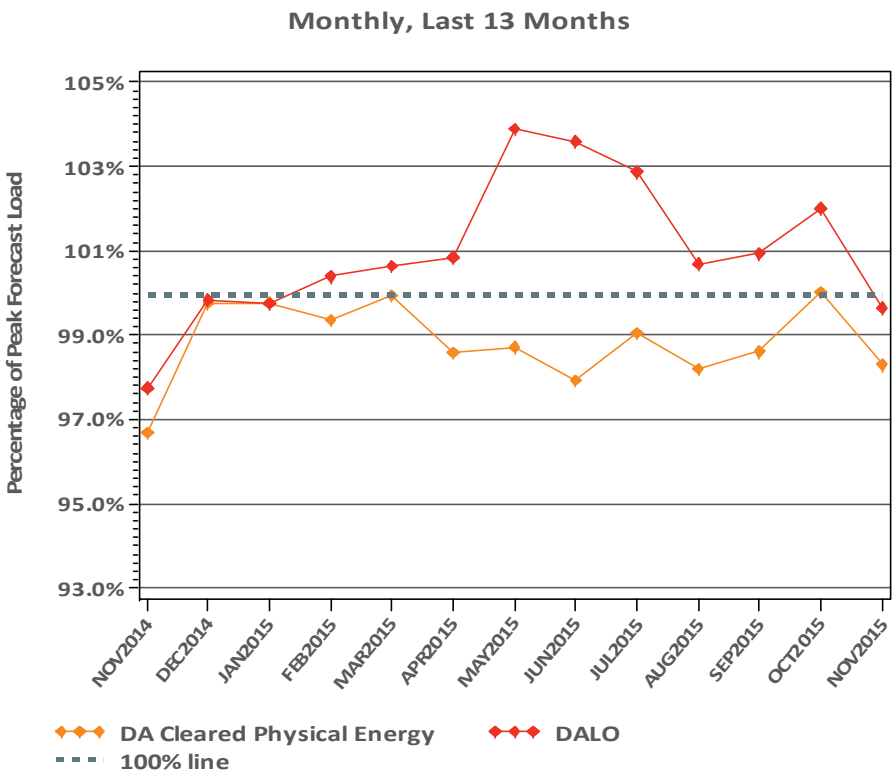
DA vs. RT Load Obligation: November, This Year vs. Last Year

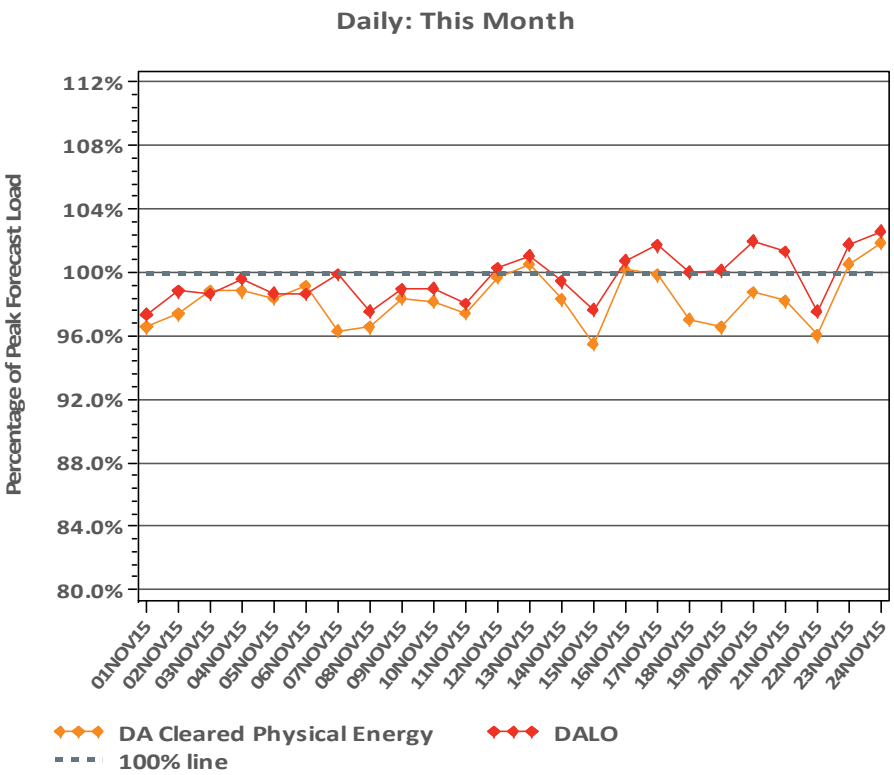




*Hourly average values

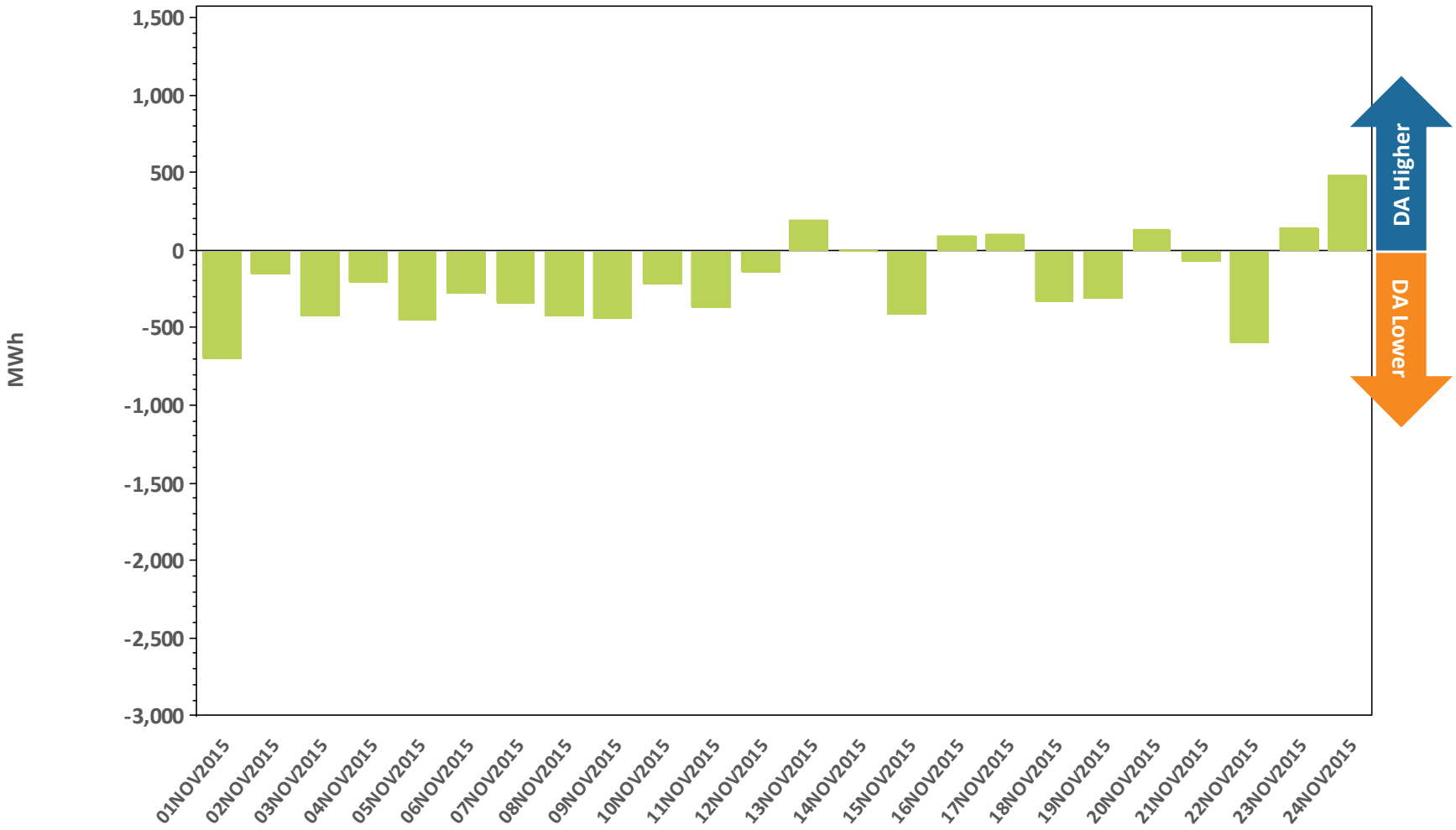
DA Volumes as % of Forecast (Peak Hour)





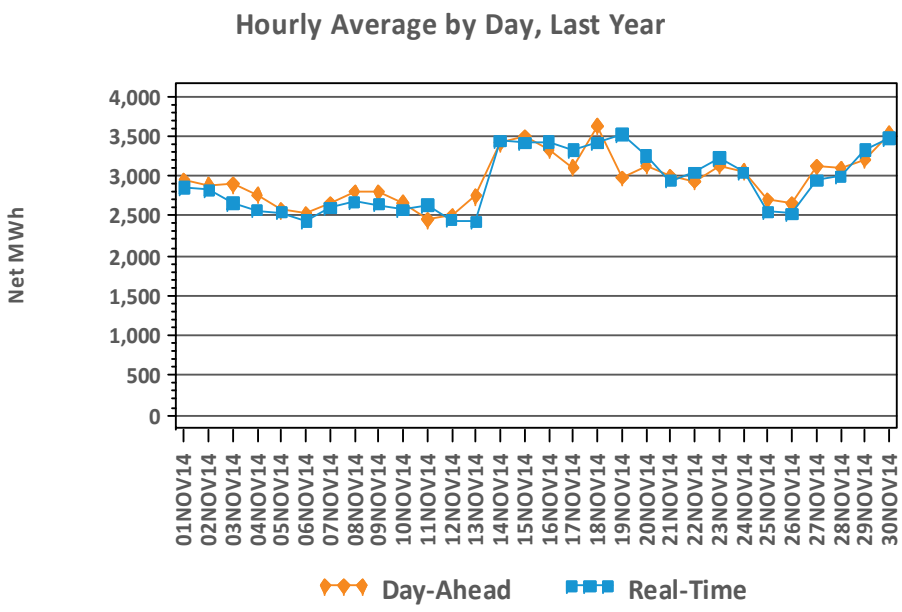
*Forecasted peak hour is reflected.

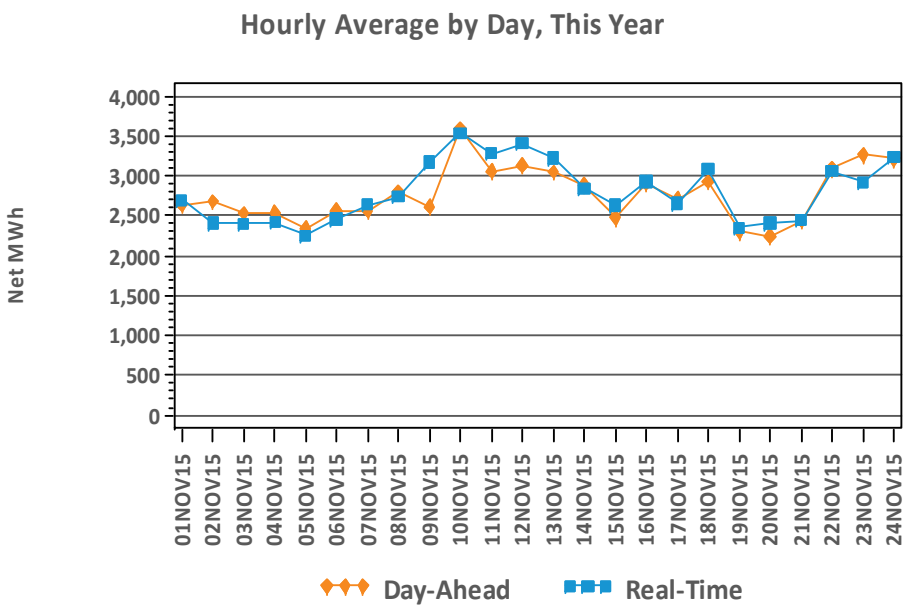
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

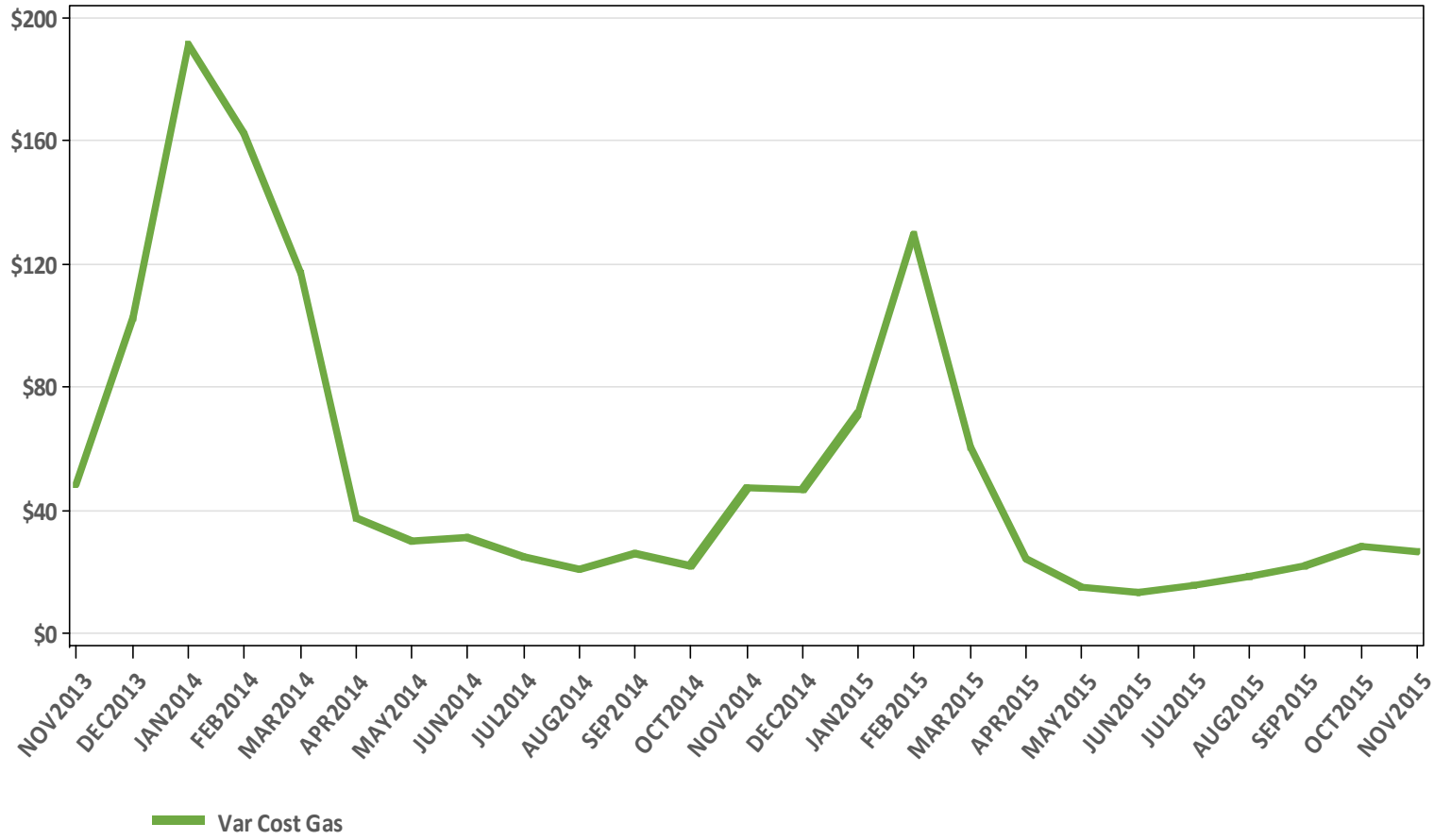
DA vs. RT Net Interchange
November 2015 vs. November 2014





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Variable Production Cost of Natural Gas: Monthly

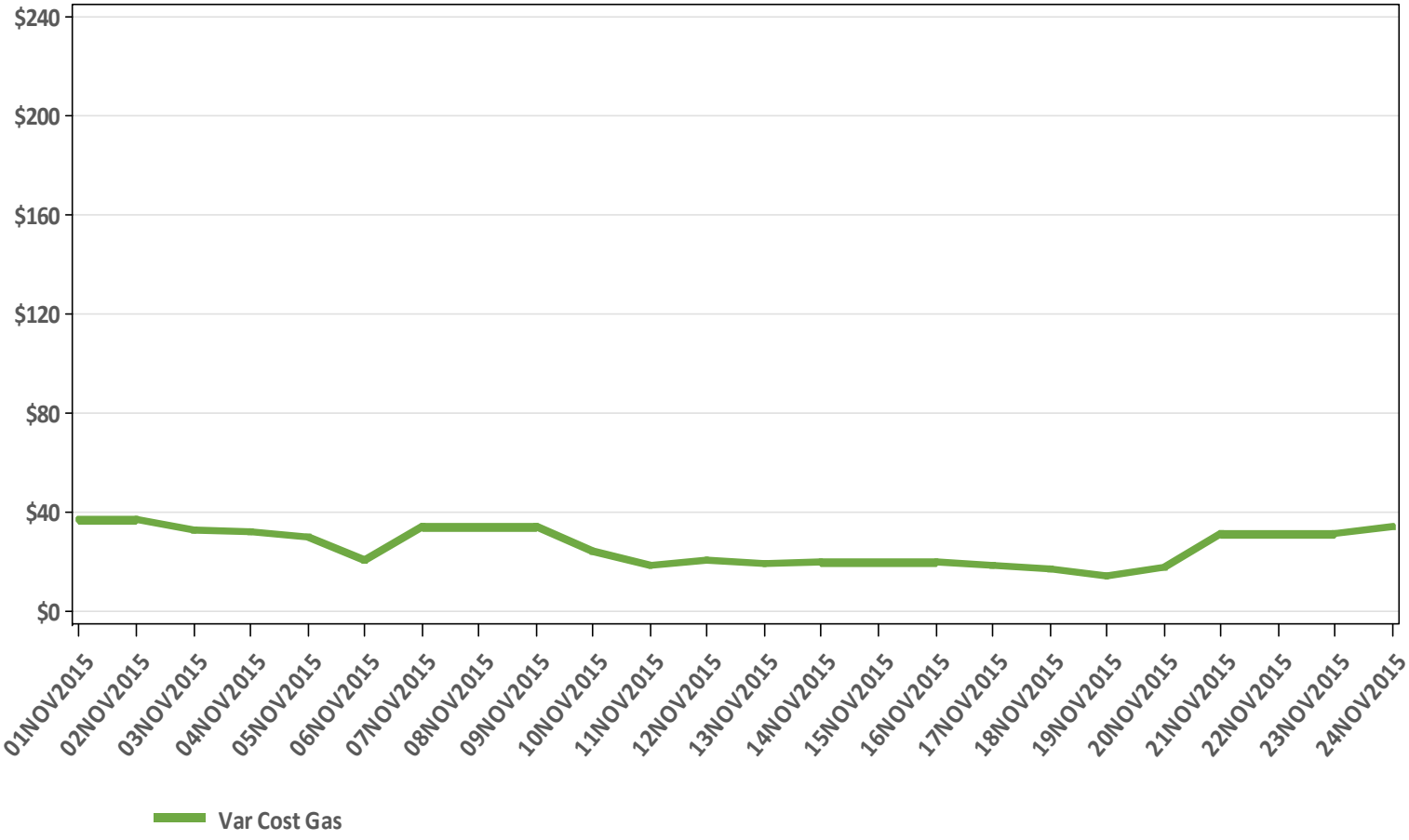


Underlying natural gas data furnished by:

ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Variable Production Cost of Natural Gas: Daily

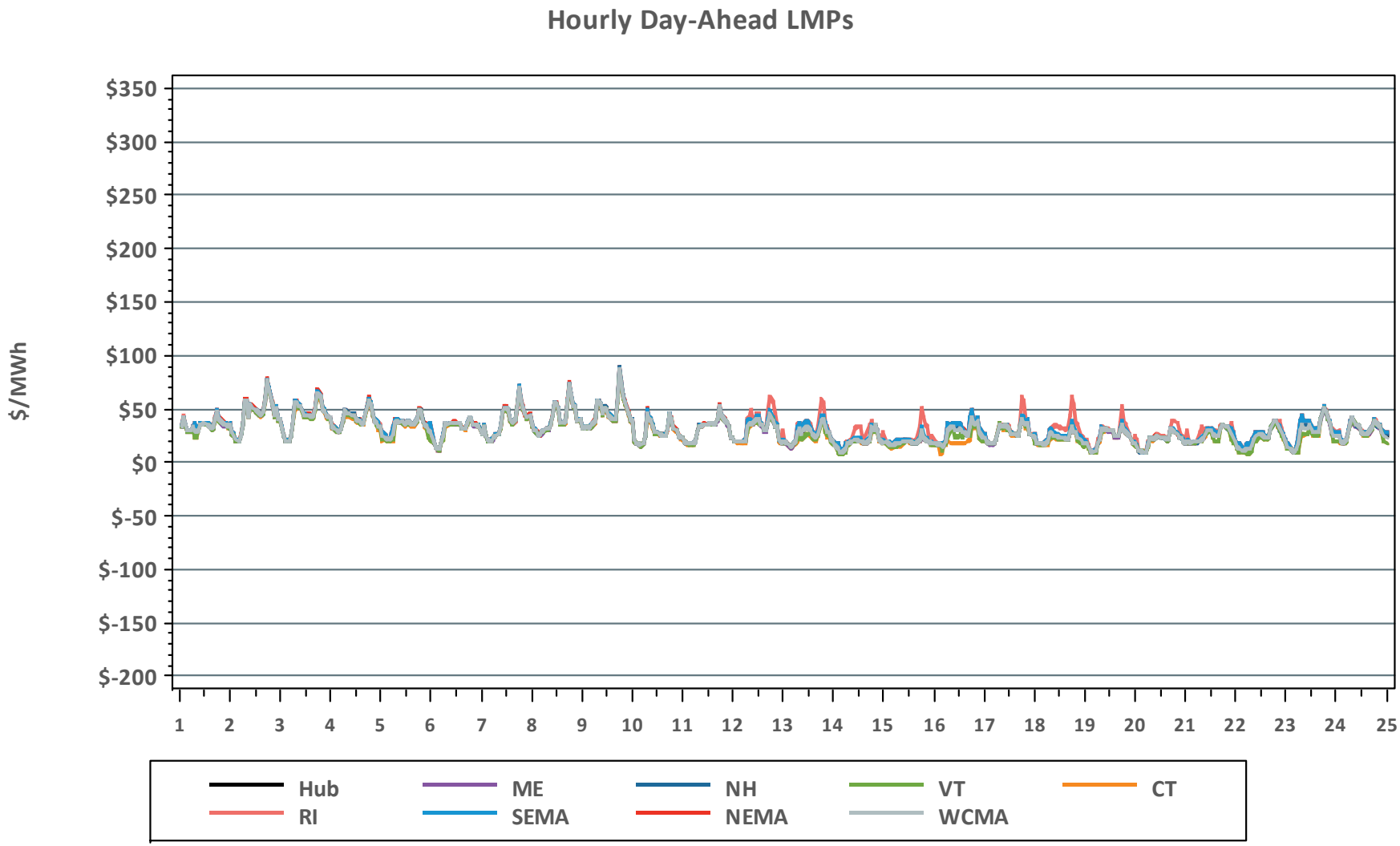


Underlying natural gas data furnished by:

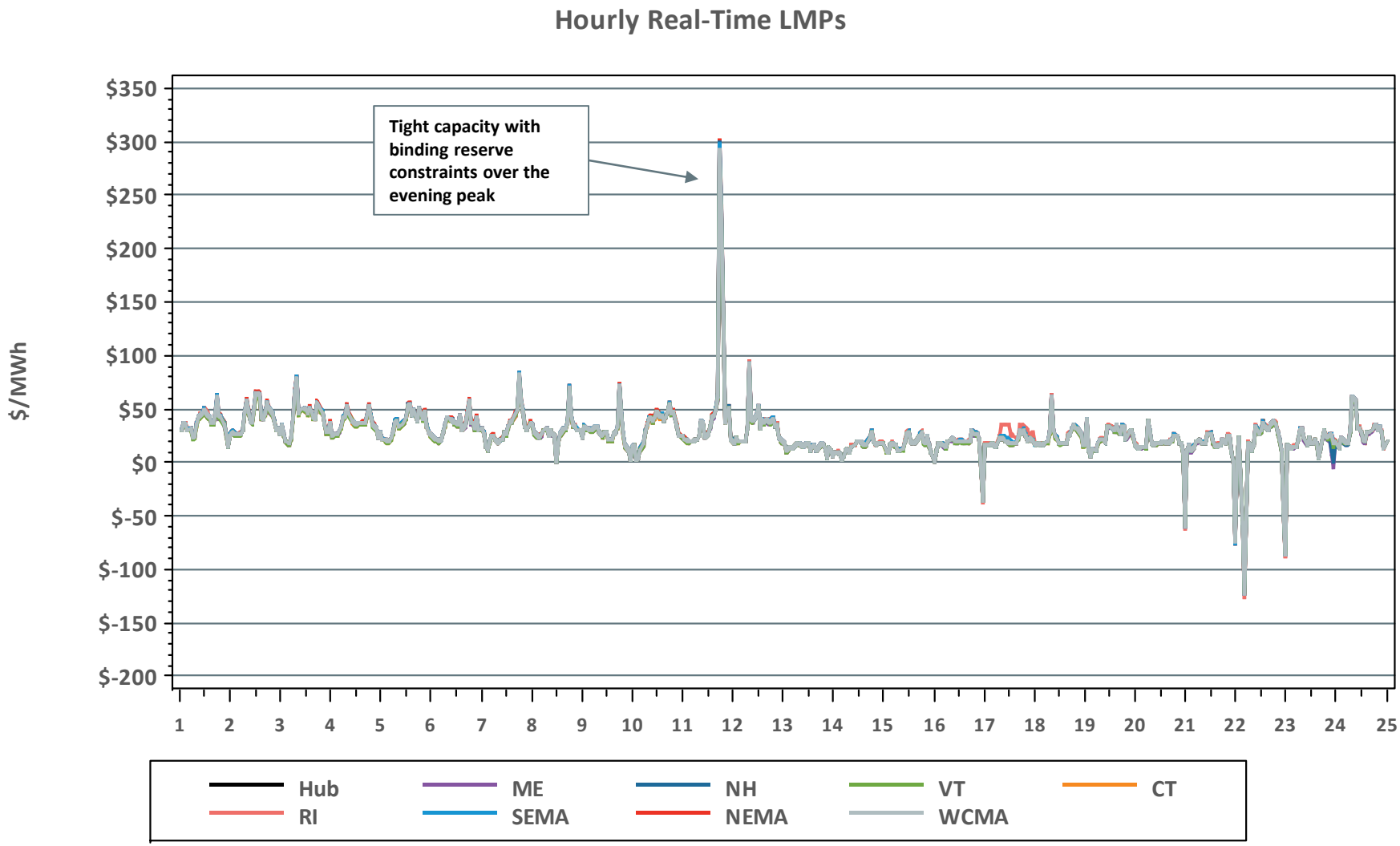
ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

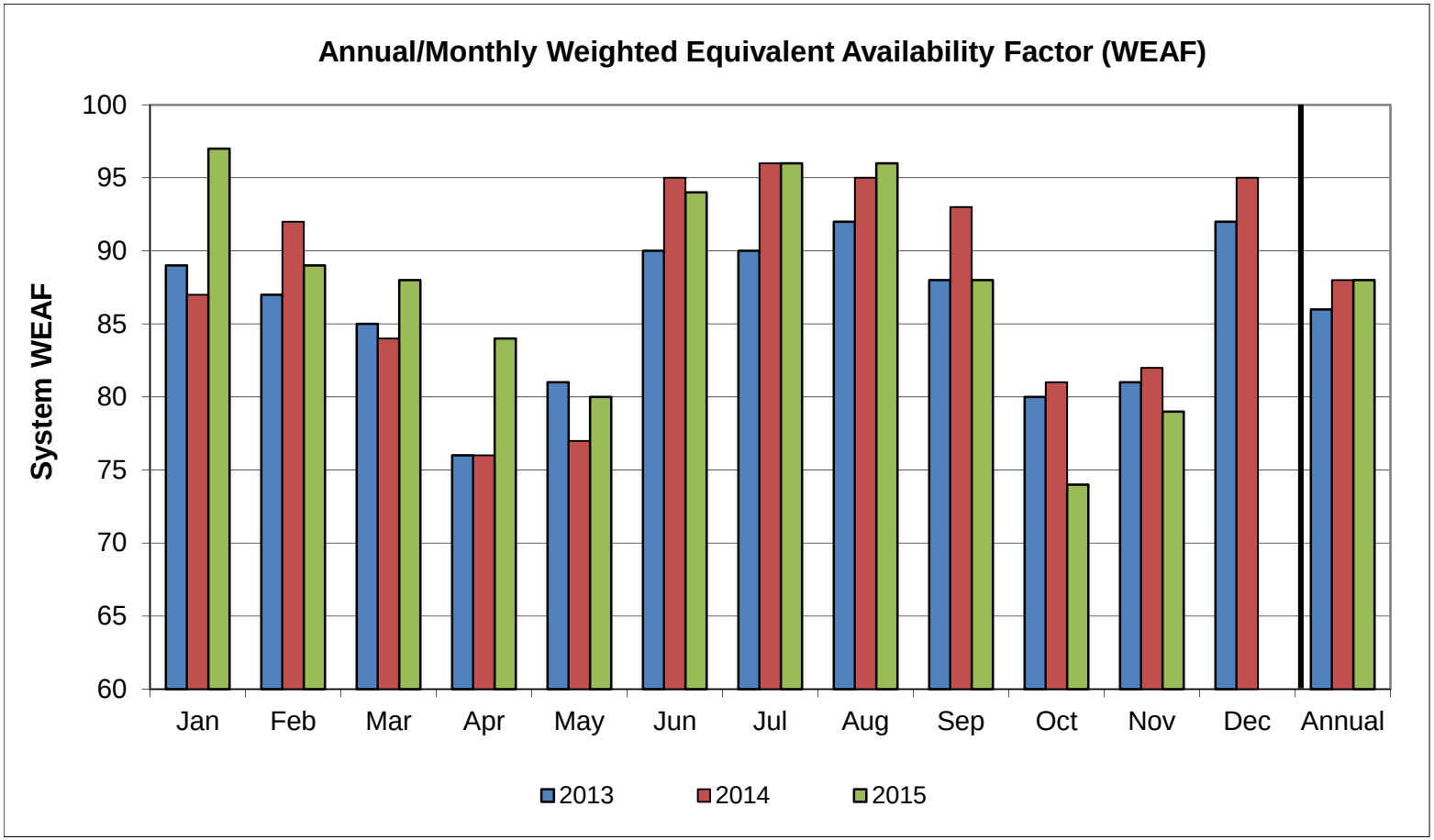
Hourly DA LMPs, November 1-24, 2015



Hourly RT LMPs, November 1-24, 2015



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2015	97	89	88	84	79	94	96	96	88	74	79		88
2014	87	92	84	76	77	95	96	95	93	81	82	95	88
2013	89	87	85	76	81	90	90	92	88	80	81	92	86
2012	93	92	88	75	83	93	95	95	91	76	80	89	88

Data as of 11/30/15

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2015

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	114.3	3.4	117.7	0.0	235.4
NH	5.2	9.8	75.3	0.0	90.3
VT	31.5	3.1	104.9	0.0	139.5
CT	66.5	80.3	71.5	310.7	529.0
RI	10.3	11.7	160.0	0.0	181.9
SEMA	5.4	8.7	202.5	0.0	216.6
WCMA	21.0	19.5	207.0	46.2	293.7
NEMA	29.4	5.6	374.0	0.0	408.9
Total	283.5	142.1	1,312.7	356.9	2,095.2

*** 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

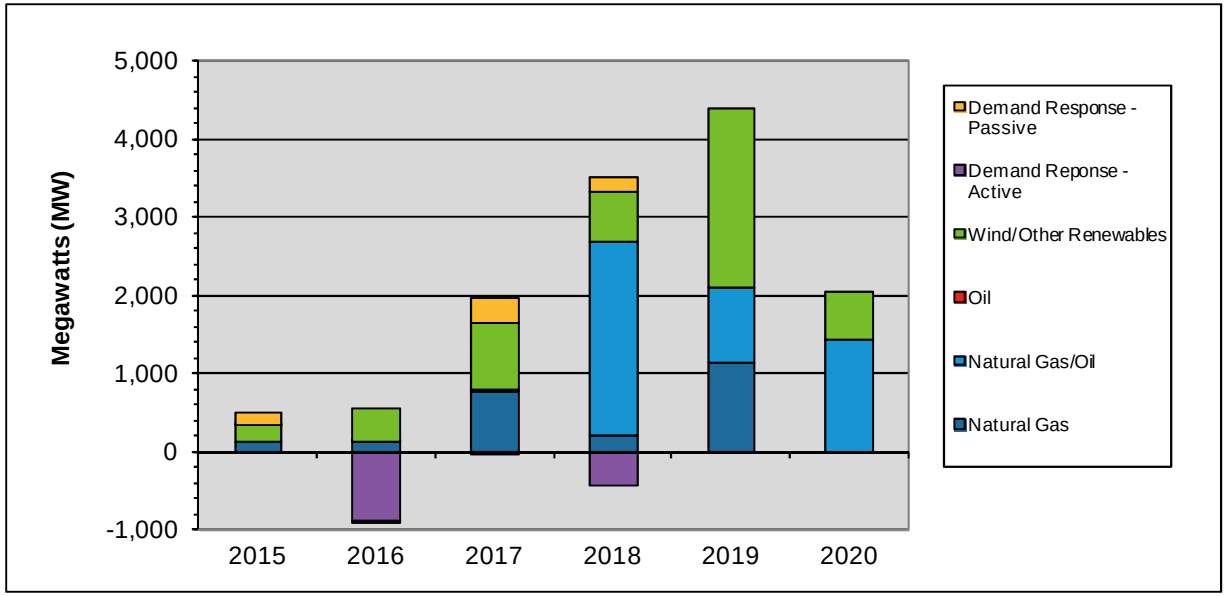
New Generation Update

Based on Queue as of 11/30/15

- Eight new projects, with a total rating of 1,369 MW, have applied for interconnection study since the last update
  - The new projects consist of three new wind plants, three new battery storage facilities that are associated with planned and existing generating plants, one new photovoltaic plant, and one new combined cycle plant that also has battery storage. The expected in-service dates range from 2016 to 2020.
- One project went commercial, resulting in a net increase in new generation projects of 1,341 MW
- In total, 85 generation projects are currently being tracked by the ISO, totaling approximately 12,000 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



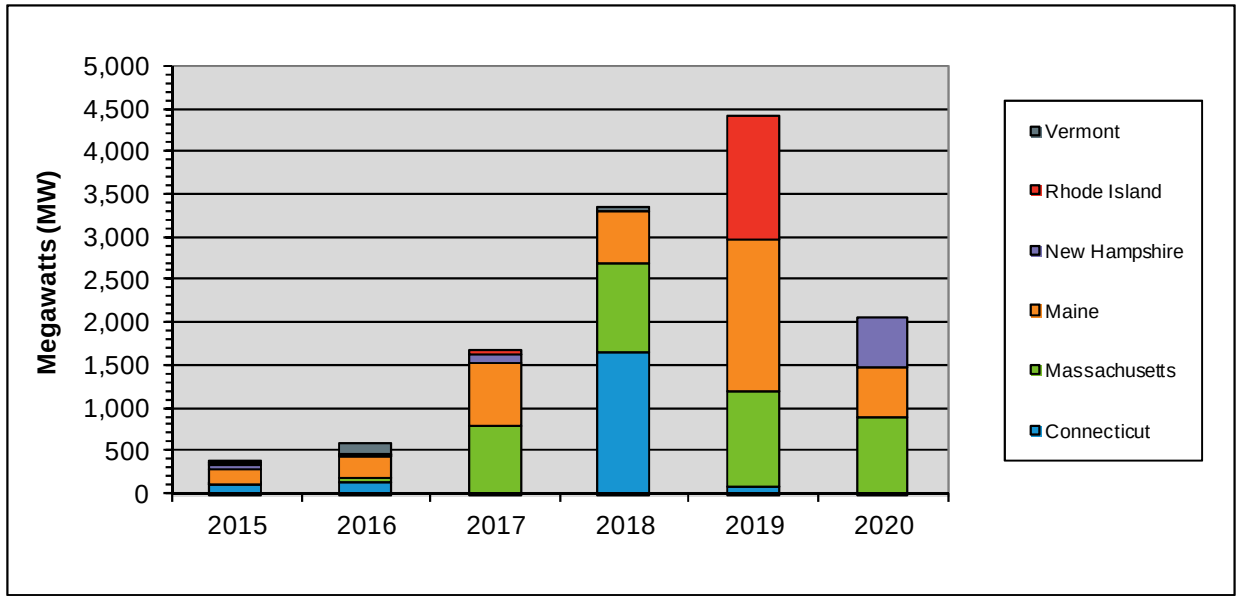
	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Demand Response - Passive	157	-12	330	196	0	0	670	5.7
Demand Response - Active	3	-868	-37	-433	0	0	-1,335	-11.4
Wind & Other Renewables	204	437	854	644	2,298	601	5,038	43.2
Oil	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	0	10	14	2,475	947	1,440	4,886	41.9
Natural Gas	139	123	786	210	1,149	0	2,407	20.6
Totals	**503**	**-310**	**1,947**	**3,092**	**4,394**	**2,041**	**11,666**	**100.0**

[1] Sum may not equal 100% due to rounding

[2] The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2015 values include the 314 MW of generation that has gone commercial in 2015
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions
By State



	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Vermont	3	117	0	30	0	0	150	1.2
Rhode Island	27	22	29	0	1,430	0	1,508	12.2
New Hampshire	40	15	120	0	0	570	745	6.0
Maine	179	255	739	607	1,781	601	4,162	33.8
Massachusetts	10	40	766	1,061	1,120	870	3,867	31.4
Connecticut	84	121	0	1,631	63	0	1,899	15.4
Totals	**343**	**570**	**1,654**	**3,329**	**4,394**	**2,041**	**12,331**	**100.0**

[1] Sum may not equal 100% due to rounding

- 2015 values include the 314 MW of generation that has gone commercial in 2015

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	0	0	1	37
Hydro	4	33	0	0	4	33
Landfill Gas	1	2	0	0	1	2
Natural Gas	14	2,331	0	0	14	2,331
Natural Gas/Oil	17	4,886	0	0	17	4,886
Oil	0	0	0	0	0	0
Solar	10	370	6	105	4	265
Wind	35	4,290	6	329	29	3,961
Battery Storage	3	68	0	0	3	68
Total	85	12,017	12	434	73	11,583

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- 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

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	3	102	0	0	3	102
Intermediate	23	5,936	0	0	23	5,936
Peaker	24	1,689	6	105	18	1,584
Wind Turbine	35	4,290	6	329	29	3,961
Total	85	12,017	12	434	73	11,583

- 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

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	1	37	0	0	0	0	0	0
Hydro	4	33	0	0	3	8	1	25	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	14	2,331	1	63	10	2,070	3	198	0	0
Natural Gas/Oil	17	4,886	0	0	10	3,858	7	1,028	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	10	370	0	0	0	0	10	370	0	0
Wind	35	4,290	0	0	0	0	0	0	35	4,290
Battery Storage	3	68	0	0	0	0	3	68	0	0
Total	85	12,017	3	102	23	5,936	24	1,689	35	4,290

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	**28,971.511**	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	**754.101**	-23.823
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
***Grand Total		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	**33,114**	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

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

** Change columns contain 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

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52	671.28	-109.926				
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157				
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	**2,325.482**	**-151.03**	**2,215.399**	**-110.083**				
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792				
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793				
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	**29,145.965**	**-290.12**	**29,615.964**	**469.999**				
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	**1,576.401**	**-40.00**	**1,576.401**	**0**				
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	**33,047.848**	**-481.15**	**33,407.764**	**359.916**				
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0				

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

** Change columns contain 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 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079	887.493	-192.59	896.202	8.709								
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211								
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,852.865**	6.498								
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,667.121	143.325								
	Intermittent	876.925	898.955	22.03	921.922	22.967								
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**								
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**								
***Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,817.438**	**311.286**								
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	0								

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

** Change columns contain 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 9

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	647.26												
	Passive Demand	2,156.151												
Demand Total		**2,803.411**												
Generator	*Non-Intermittent*	29,550.564												
	Intermittent	891.616												
Generator Total		**30,442.18**												
Import Total		**1,449**												
***Grand Total**		**34,694.591**												
Net ICR (NICR)		**34,189**												

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

** Change columns contain 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.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	**1365.61**	**1187.952**	**2553.562**
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	**2488.372**	**448.24**	**2936.612**
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	**2588.15**	**309.488**	**2897.638**
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	**2834.308**	**515.134**	**3349.442**
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	**3326.837**	**263.017**	**3589.854**
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	**3331.291**	**313.553**	**3644.844**
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	**2503.028**	**245.005**	**2748.033**
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	**2685.74**	**354.856**	**3040.596**
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	**2436.415**	**366.996**	**2803.411**

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- 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

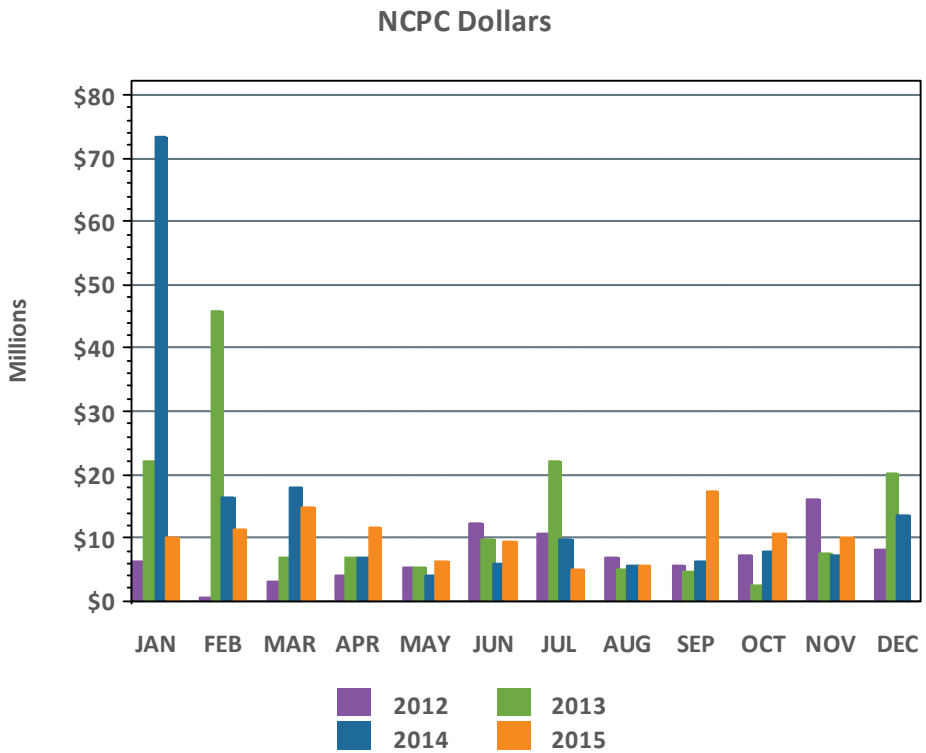
Definitions

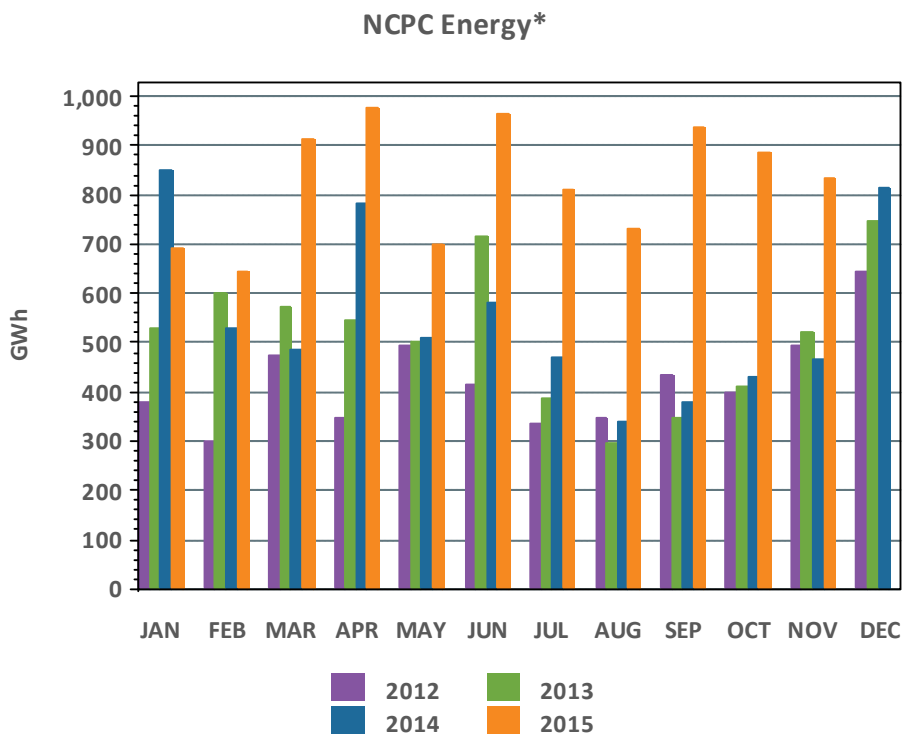
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	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
Delisted Units	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
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st 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)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Min Generation Emergency, and Generator and DARD NCPC

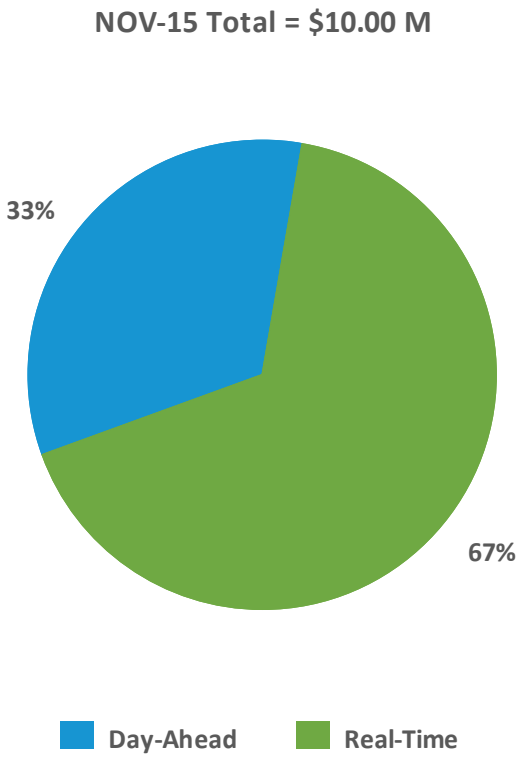
Year-Over-Year Total NCPC Dollars and Energy

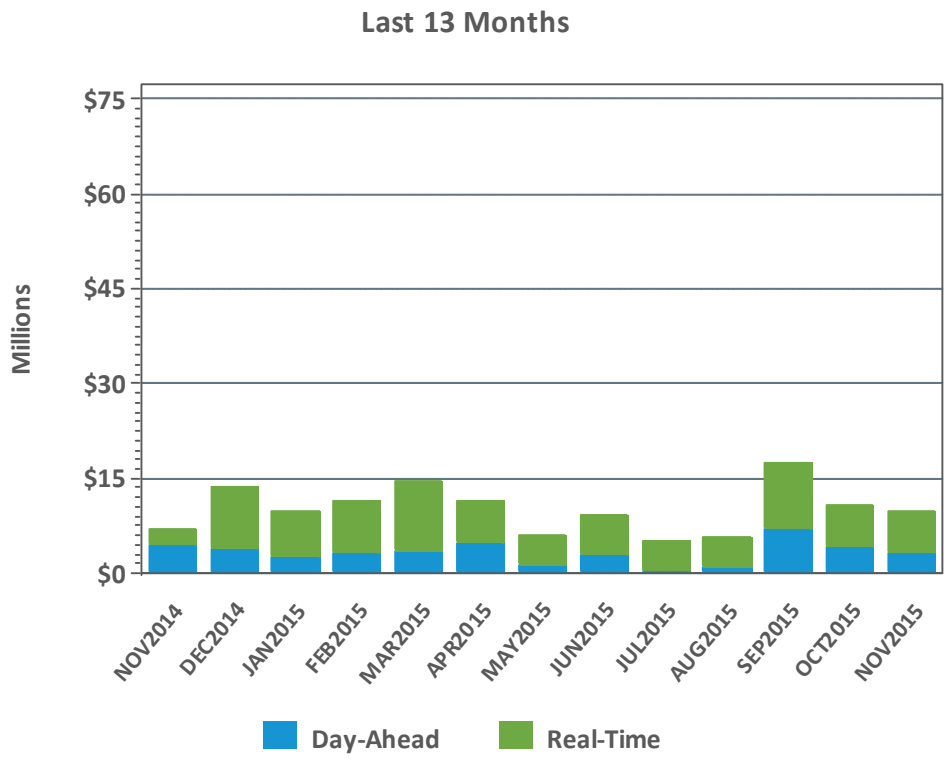




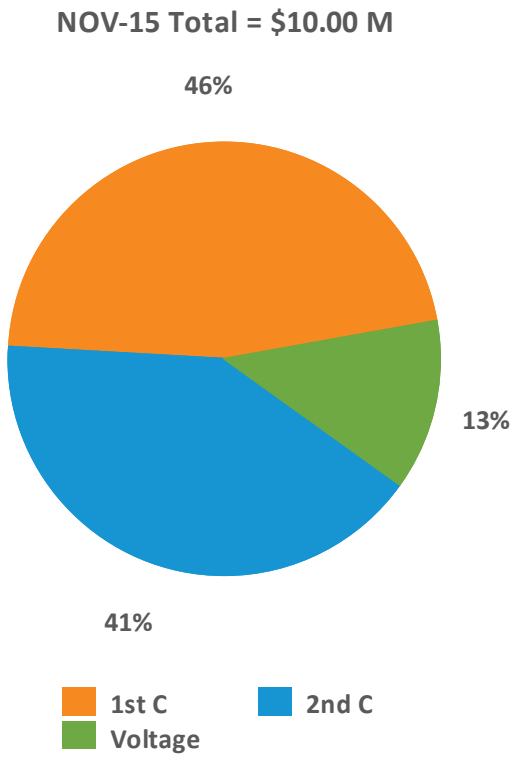
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

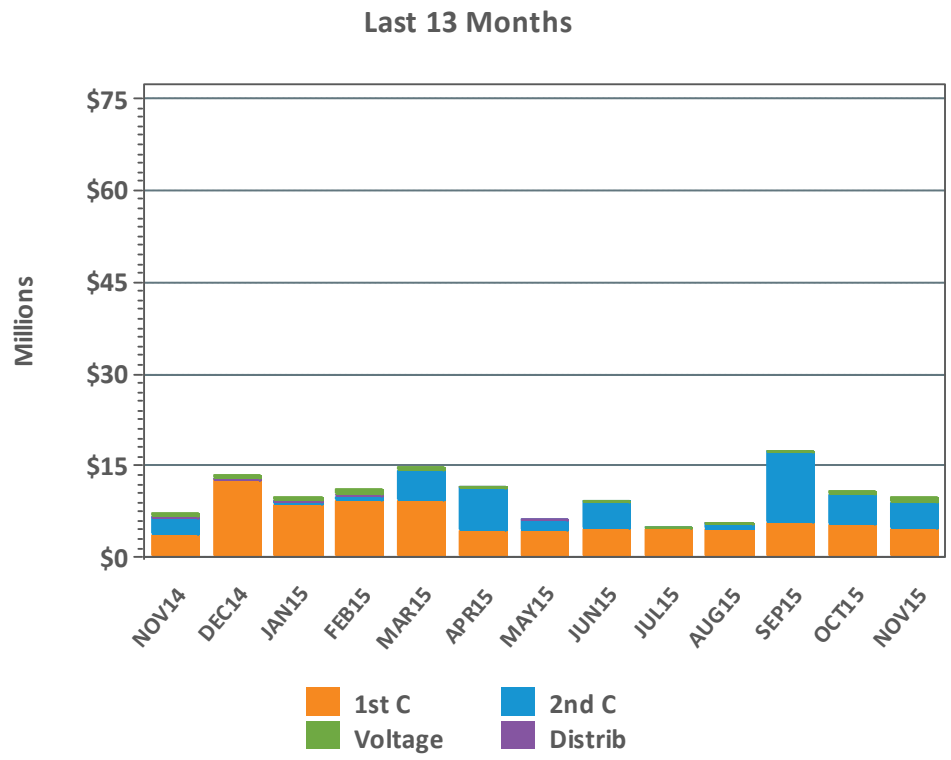
DA and RT NCPC Charges





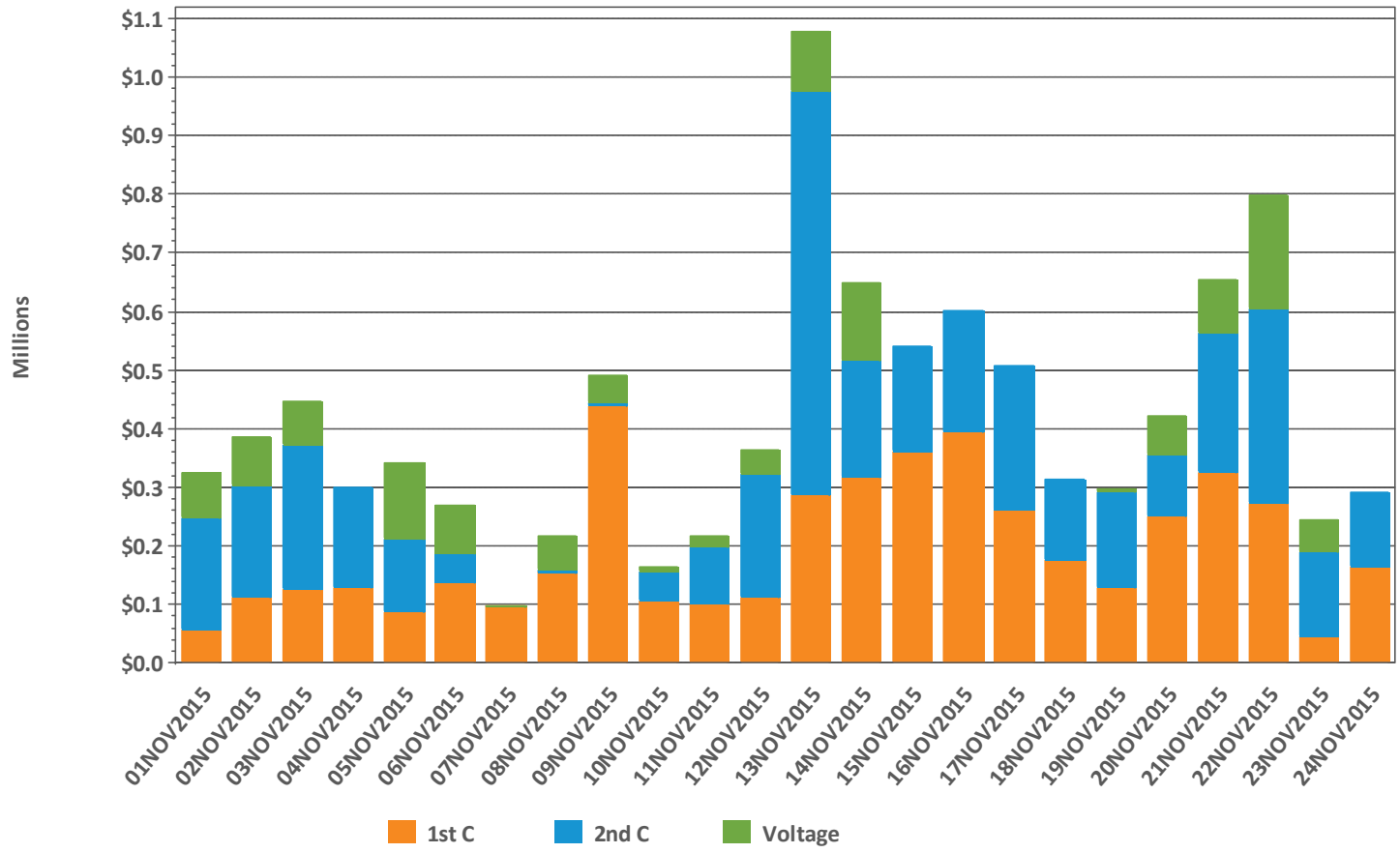
NCPC Charges by Type



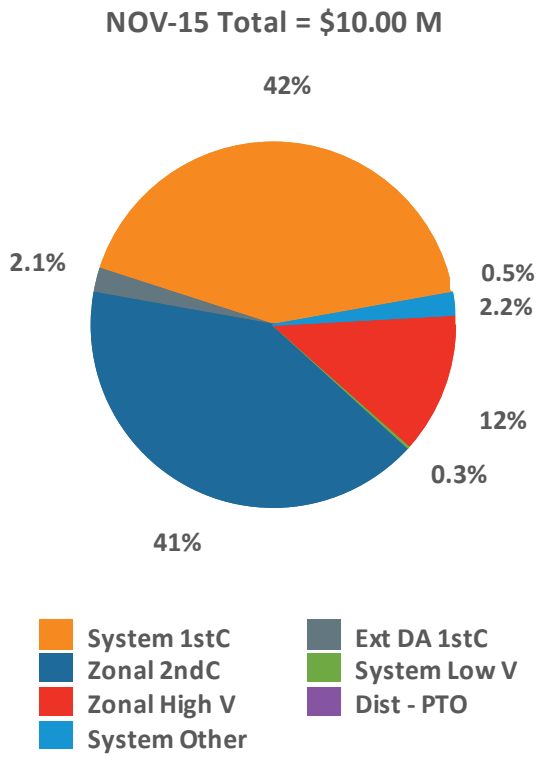


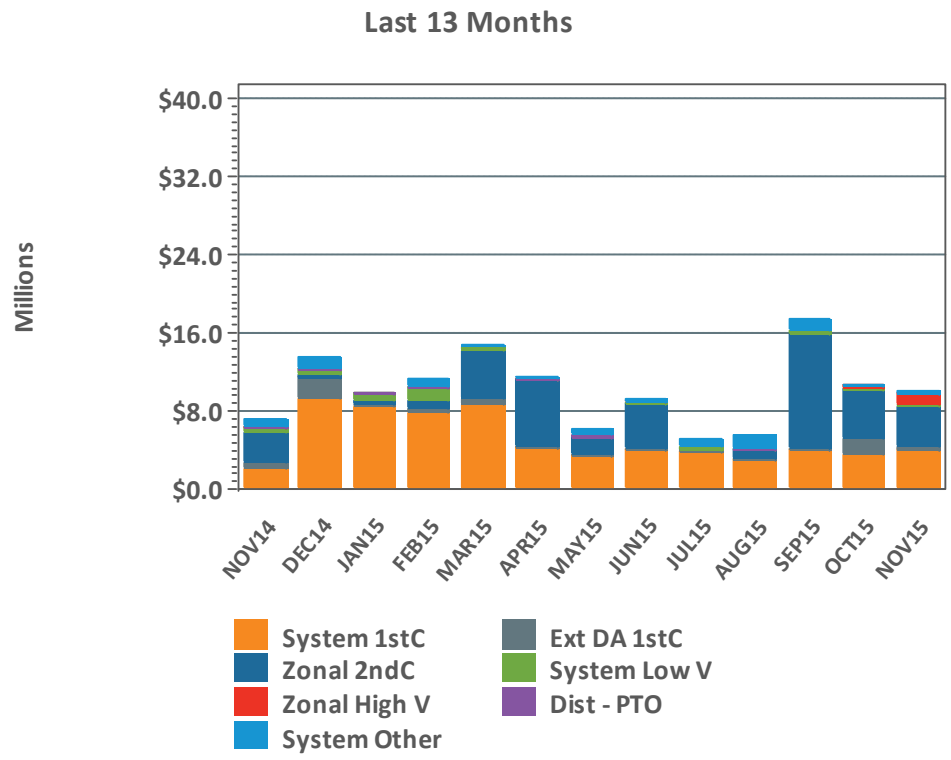
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

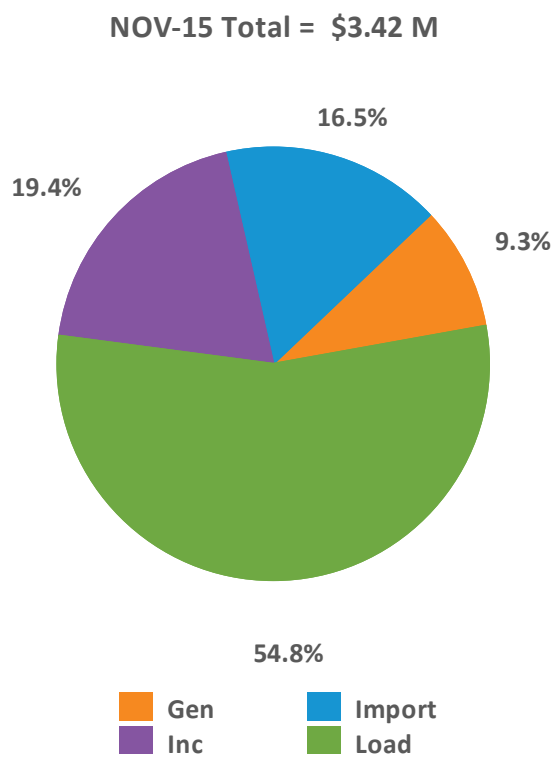


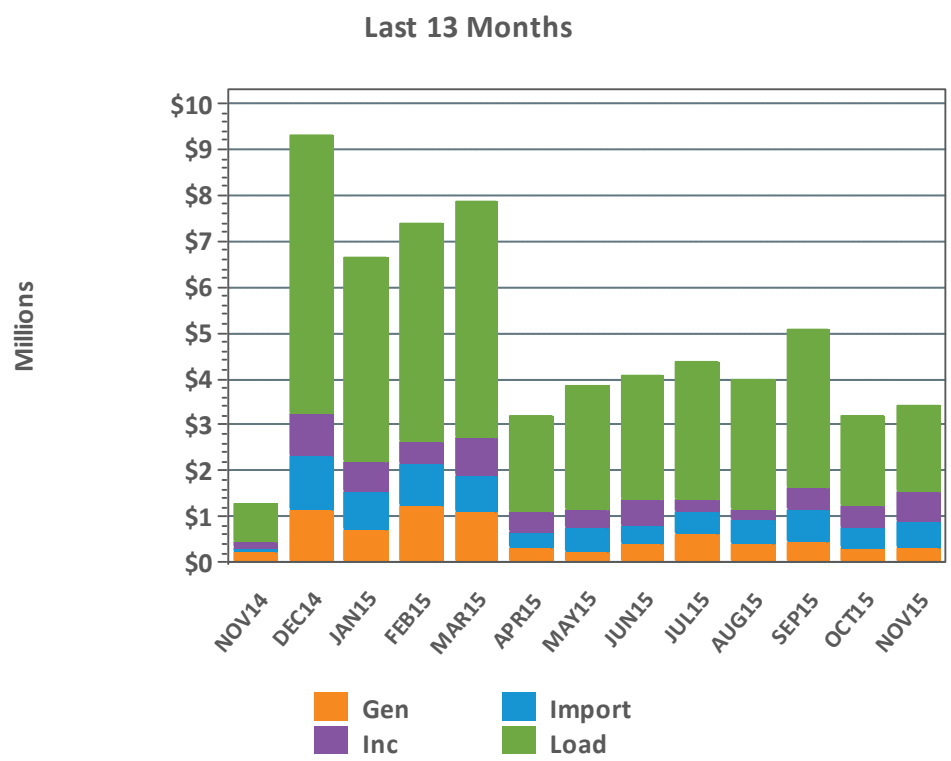
NCPC Charges by Allocation





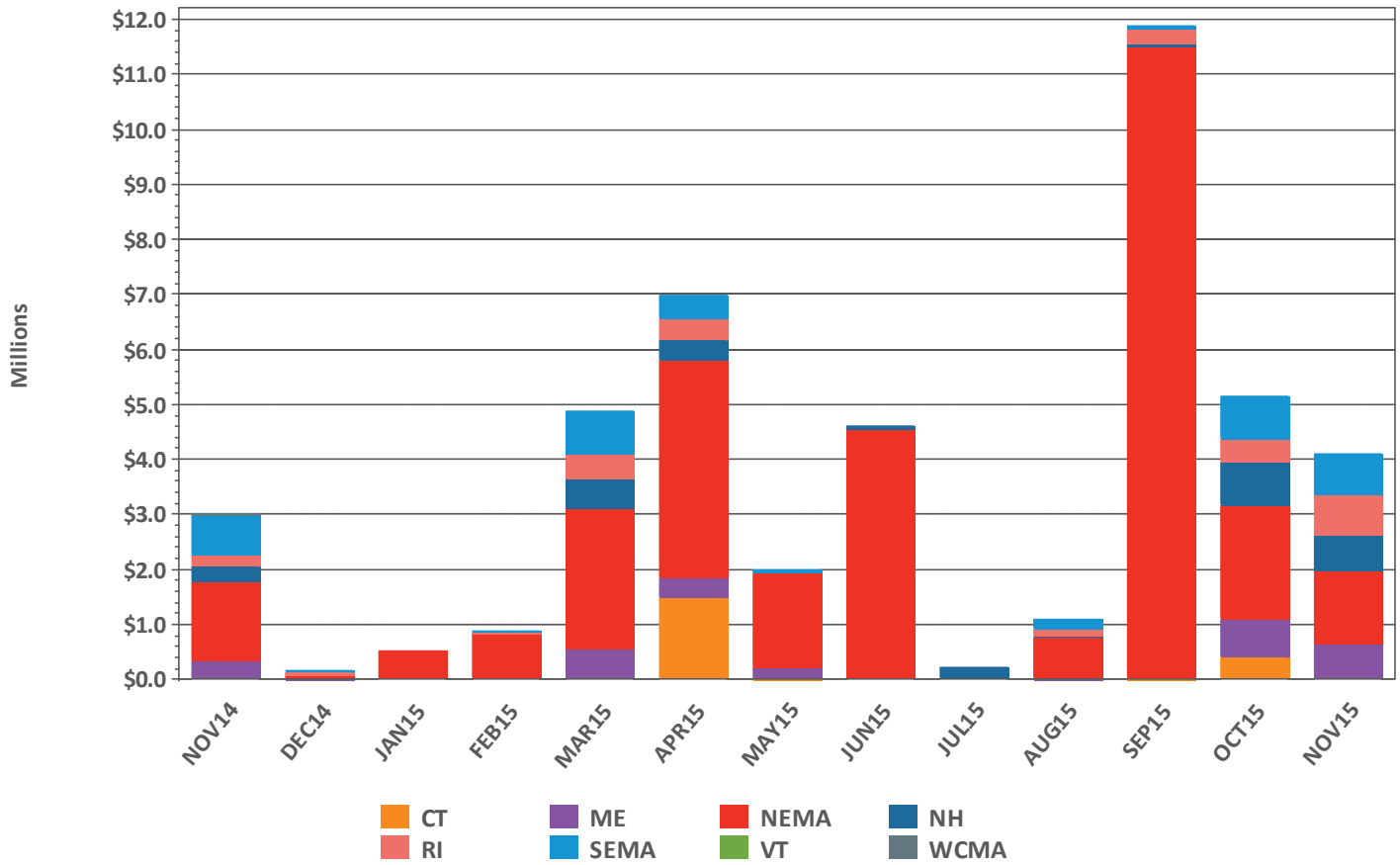
RT First Contingency Charges by Deviation Type





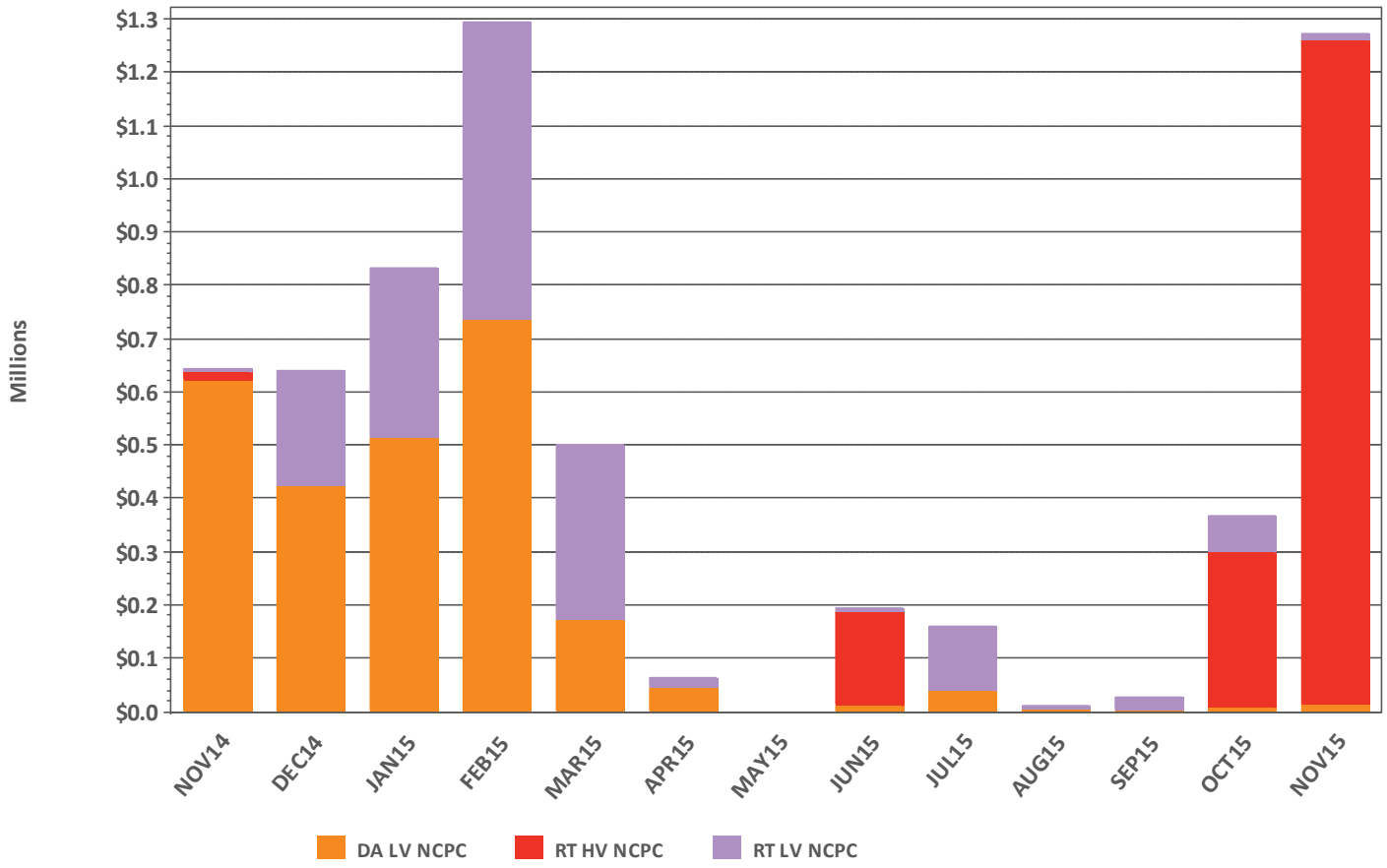
Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

LSCPR Charges by Zone

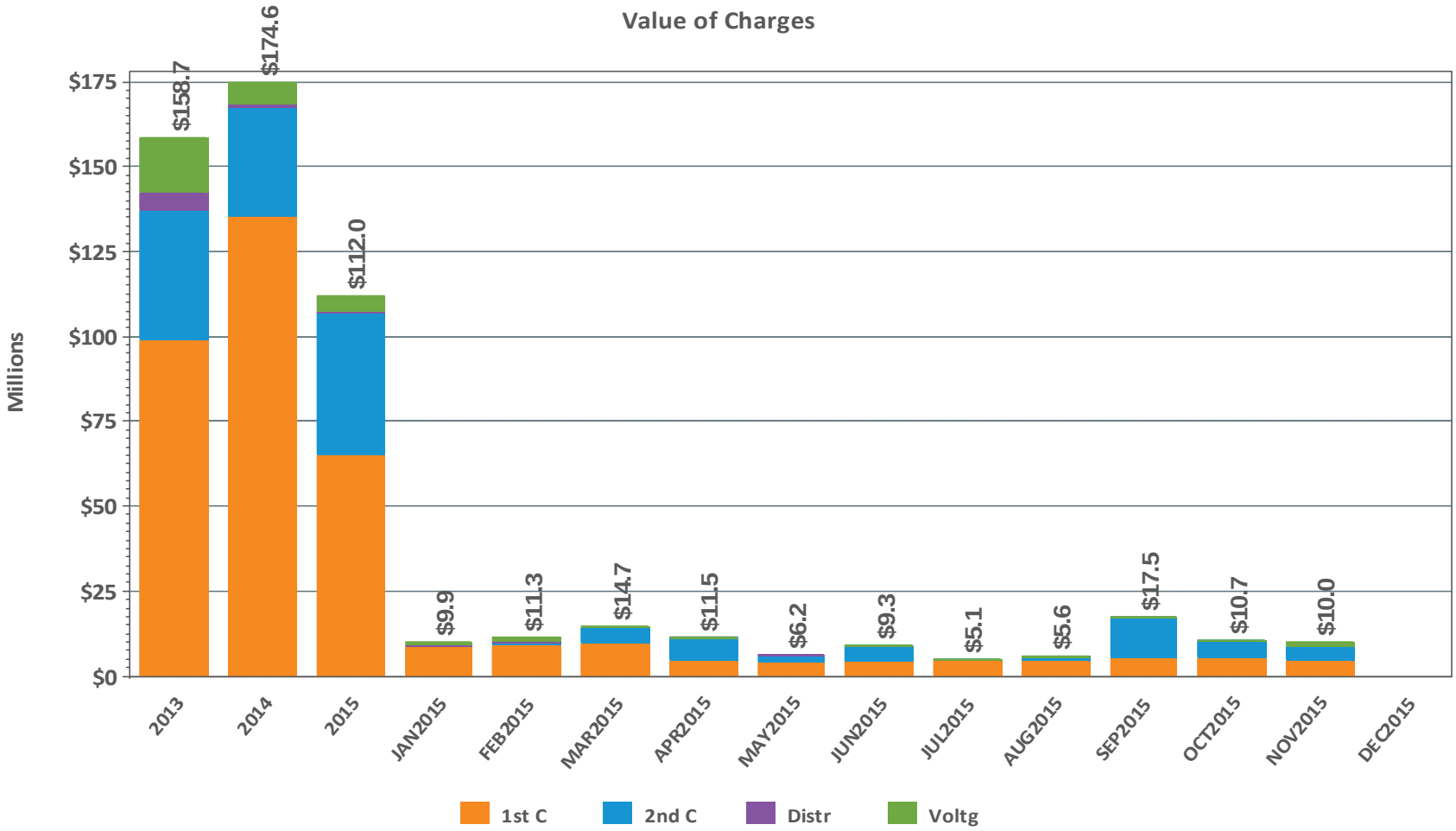


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

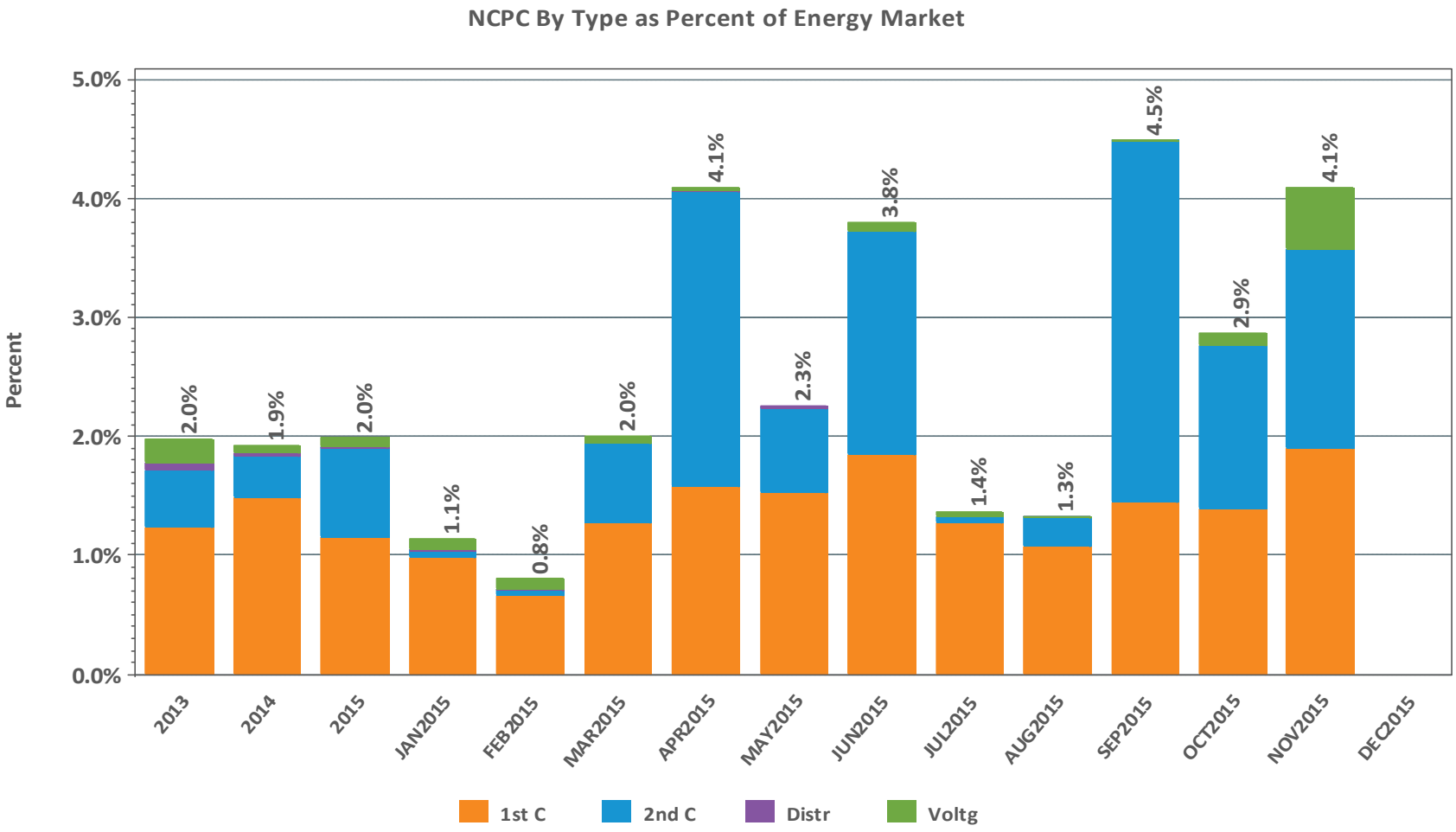
NCPC Charges for Voltage Support and High Voltage Control



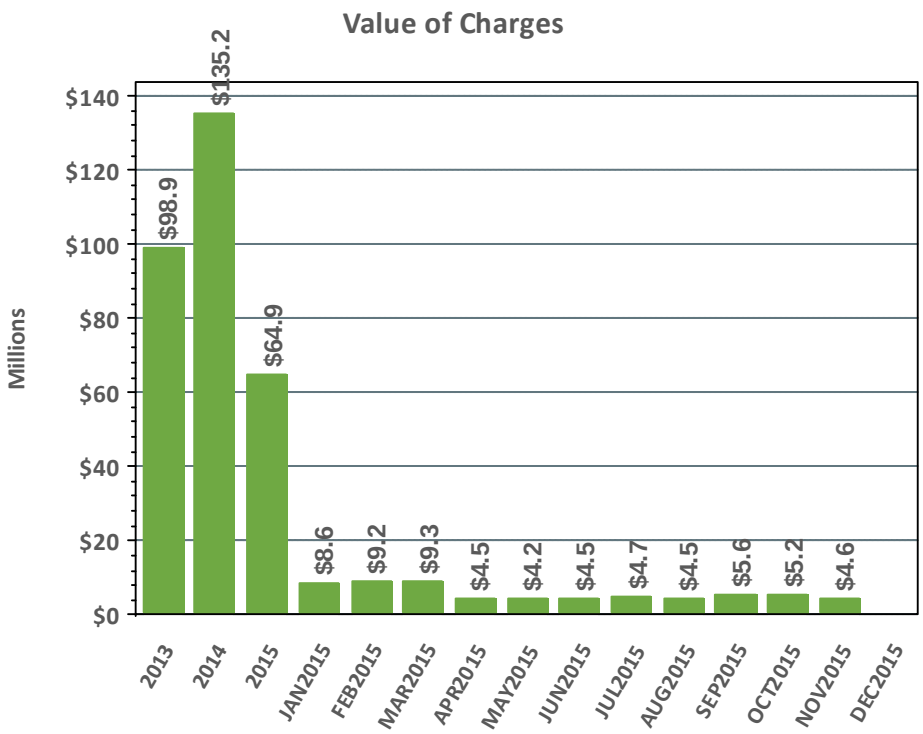
NCPC Charges by Type

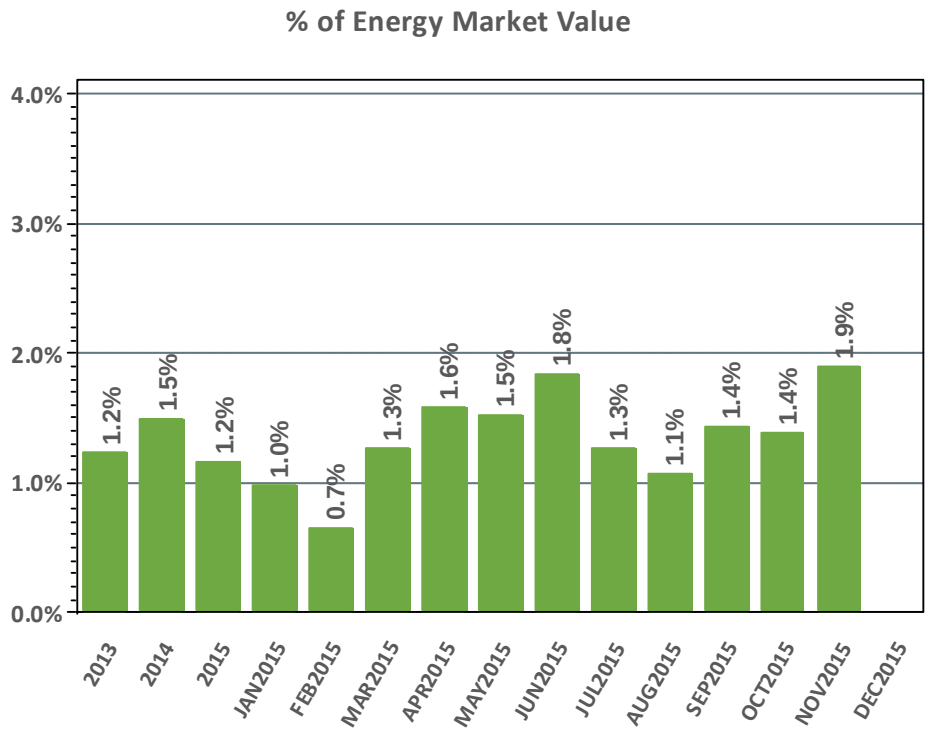


NCPC Charges as Percent of Energy Market



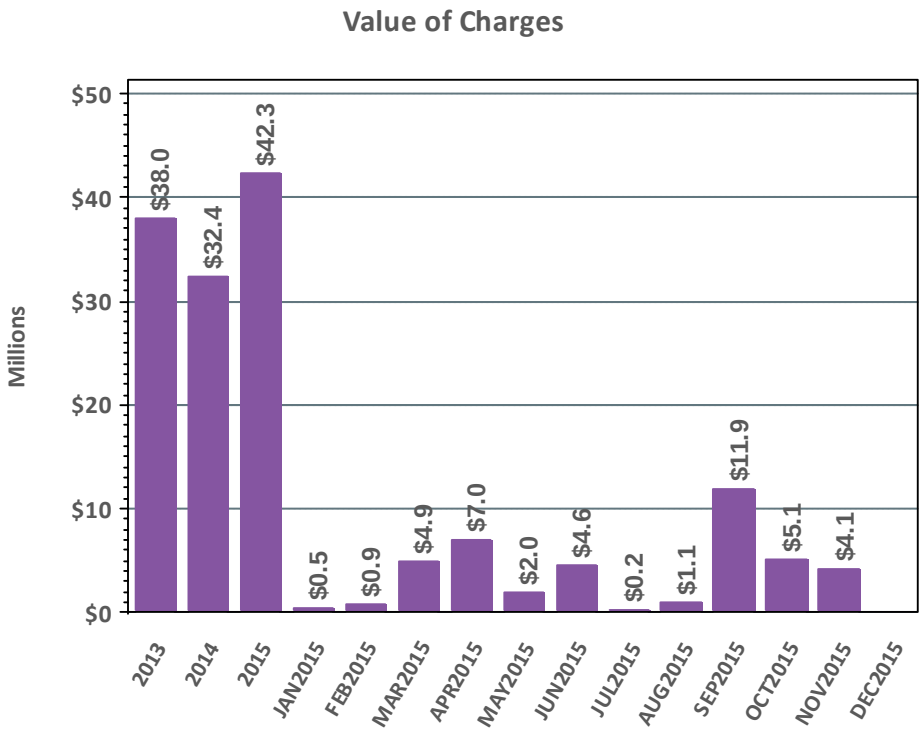
First Contingency NCPC Charges

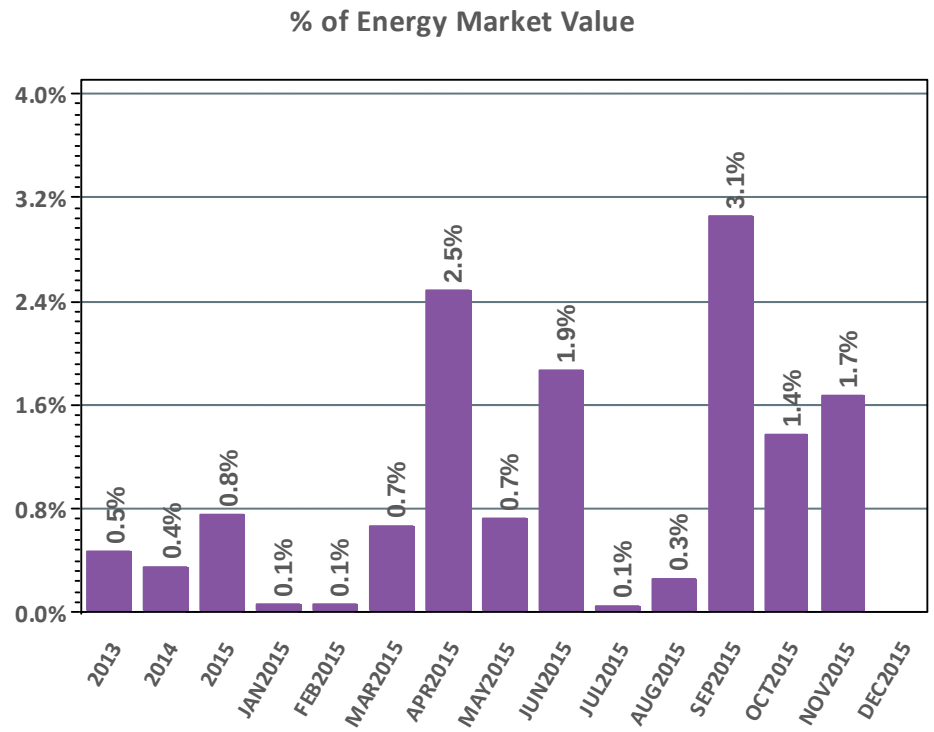




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

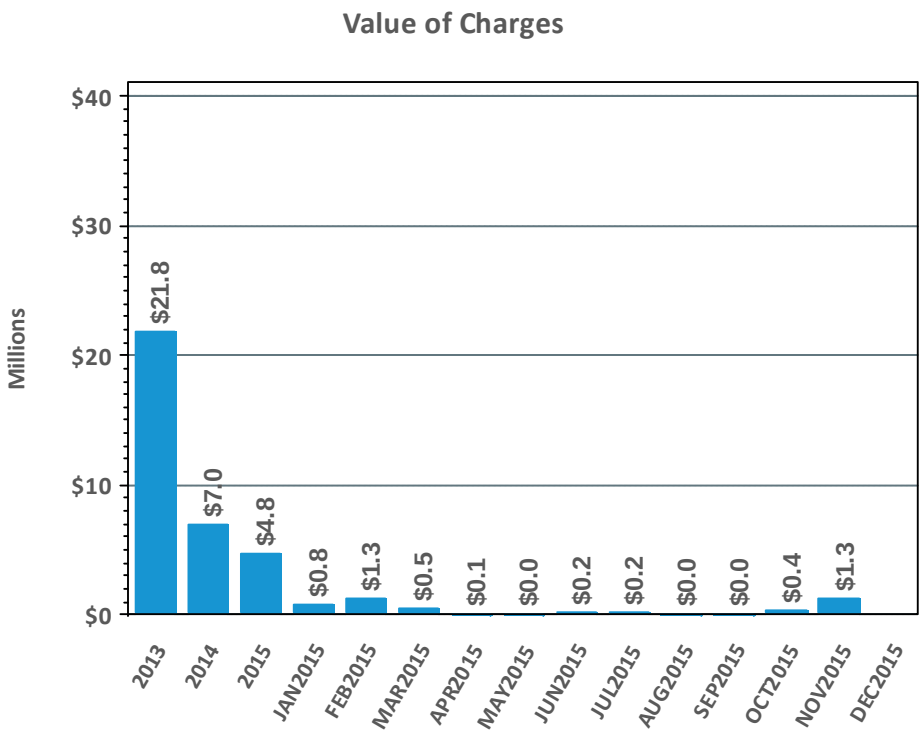
Second Contingency NCPC Charges

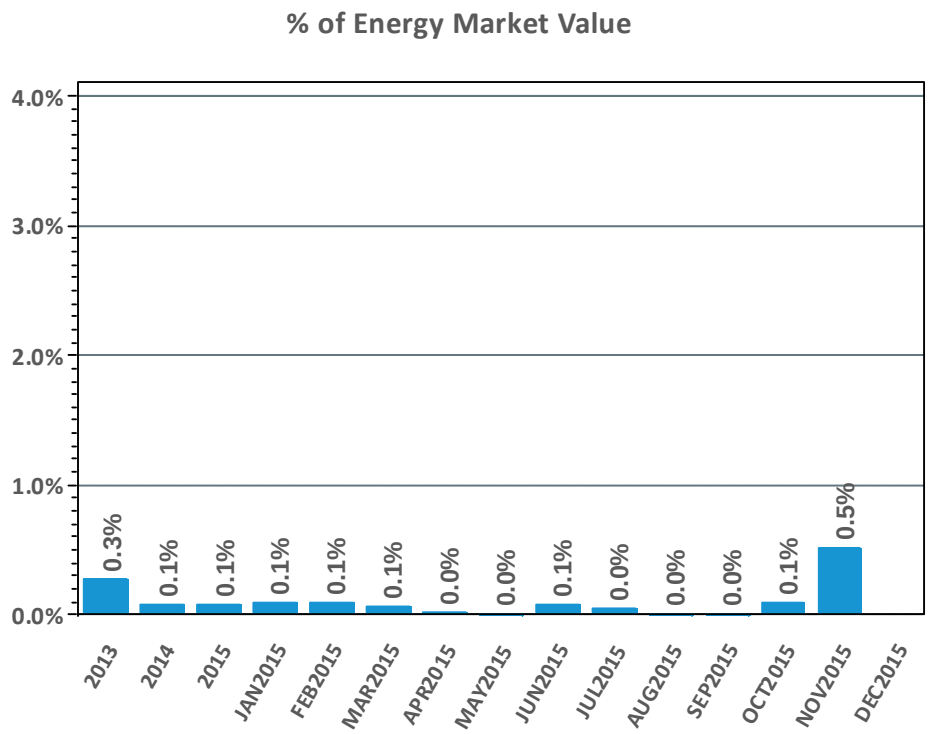




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution 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

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

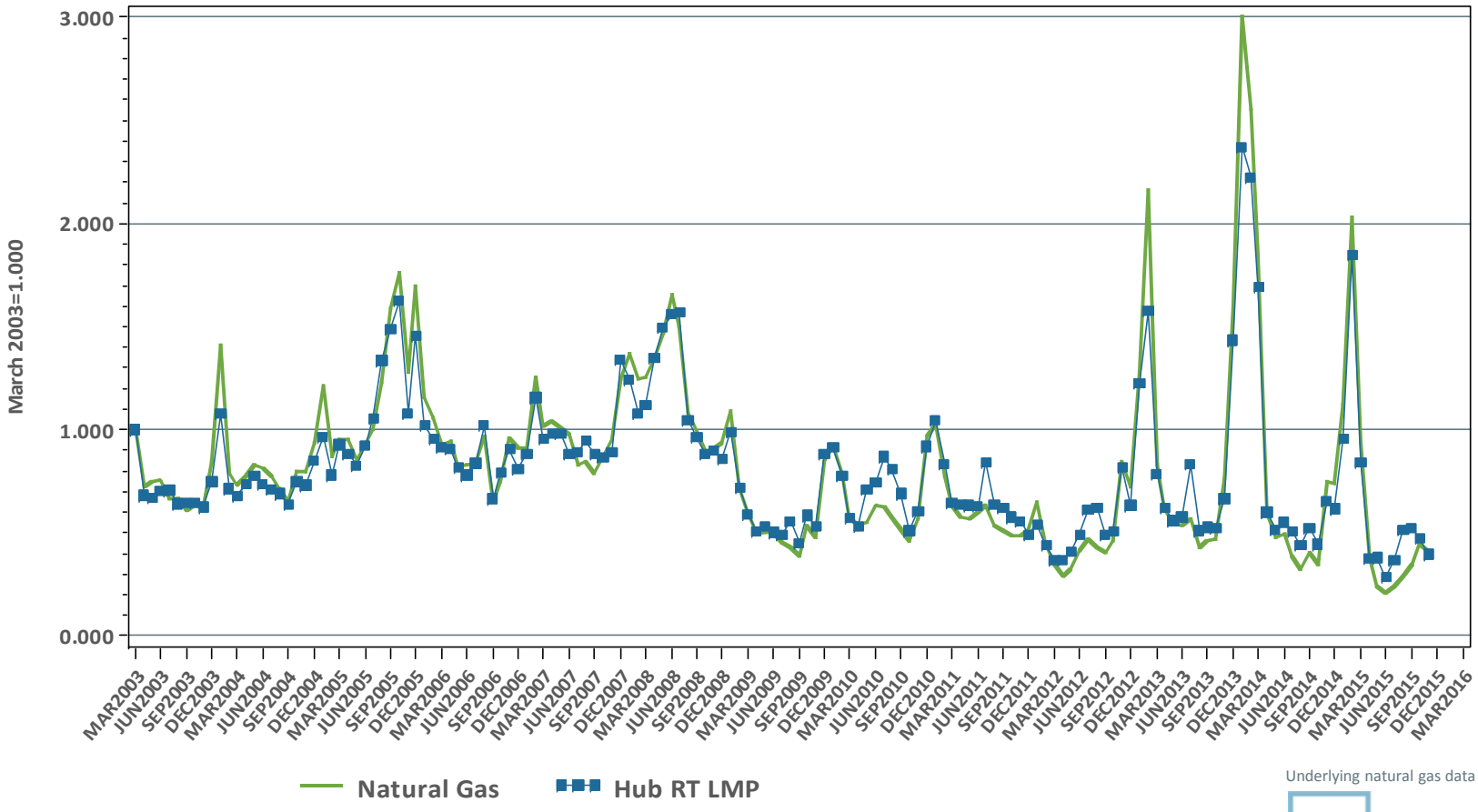
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.90	$55.43	$54.48	$55.98	$55.36	$57.80	$57.02	$56.38	$56.43
Real-Time	$56.32	$55.90	$53.23	$55.15	$55.08	$56.10	$56.43	$56.12	$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%
Year 2014	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$64.98	$64.10	$61.95	$64.12	$63.82	$64.98	$64.71	$64.66	$64.57
Real-Time	$64.03	$63.11	$59.04	$61.48	$61.60	$63.34	$63.45	$63.29	$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%

November-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$48.39	$47.10	$46.24	$47.52	$46.26	$47.92	$48.17	$47.72	$47.72
Real-Time	$45.26	$44.67	$42.59	$43.42	$43.12	$44.80	$44.94	$44.83	$44.88
RT Delta %	-6.5%	-5.2%	-7.9%	-8.6%	-6.8%	-6.5%	-6.7%	-6.1%	-6.0%
November-15	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$32.28	$29.27	$31.17	$31.57	$29.77	$32.97	$32.22	$31.01	$31.14
Real-Time	$27.73	$26.67	$26.61	$27.23	$26.54	$27.60	$27.50	$27.22	$27.27
RT Delta %	-14.1%	-8.9%	-14.6%	-13.8%	-10.8%	-16.3%	-14.6%	-12.2%	-12.4%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-33.3%	-37.9%	-32.6%	-33.6%	-35.6%	-31.2%	-33.1%	-35.0%	-34.8%
Yr over Yr RT	-38.7%	-40.3%	-37.5%	-37.3%	-38.4%	-38.4%	-38.8%	-39.3%	-39.2%

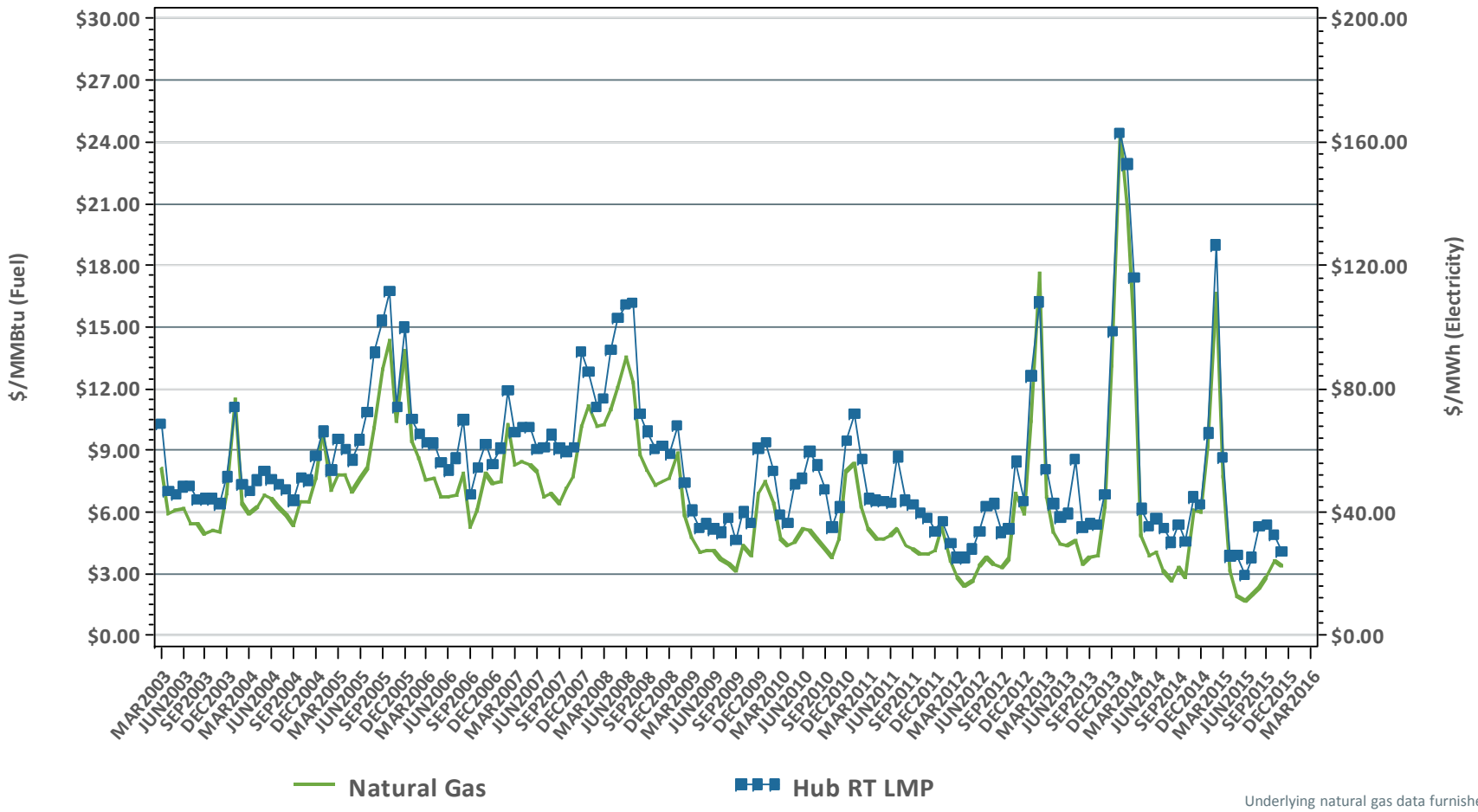
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

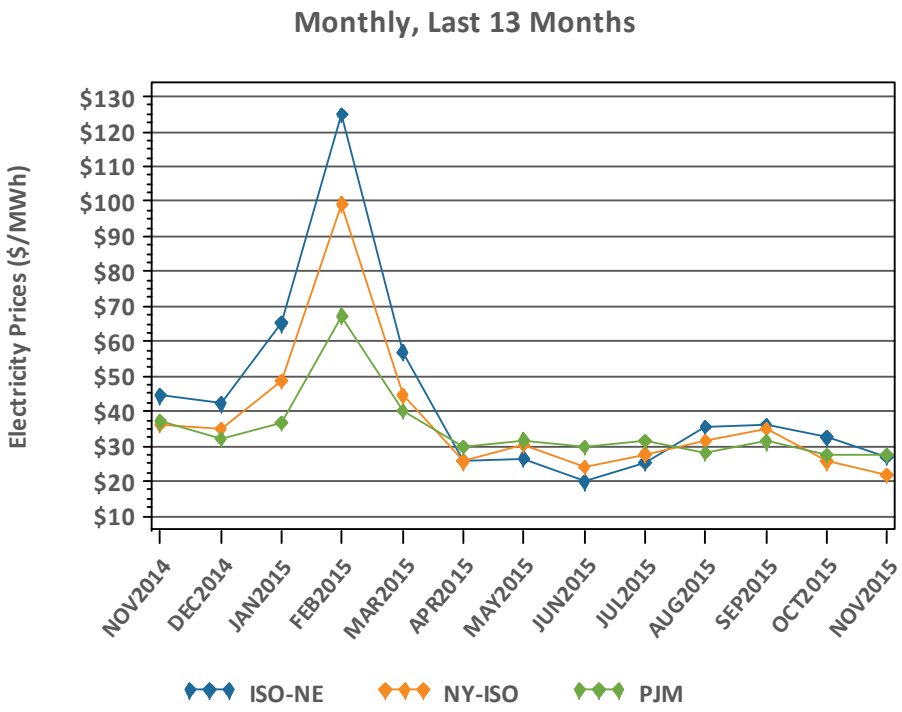
Monthly Average Fuel Price and RT Hub LMP



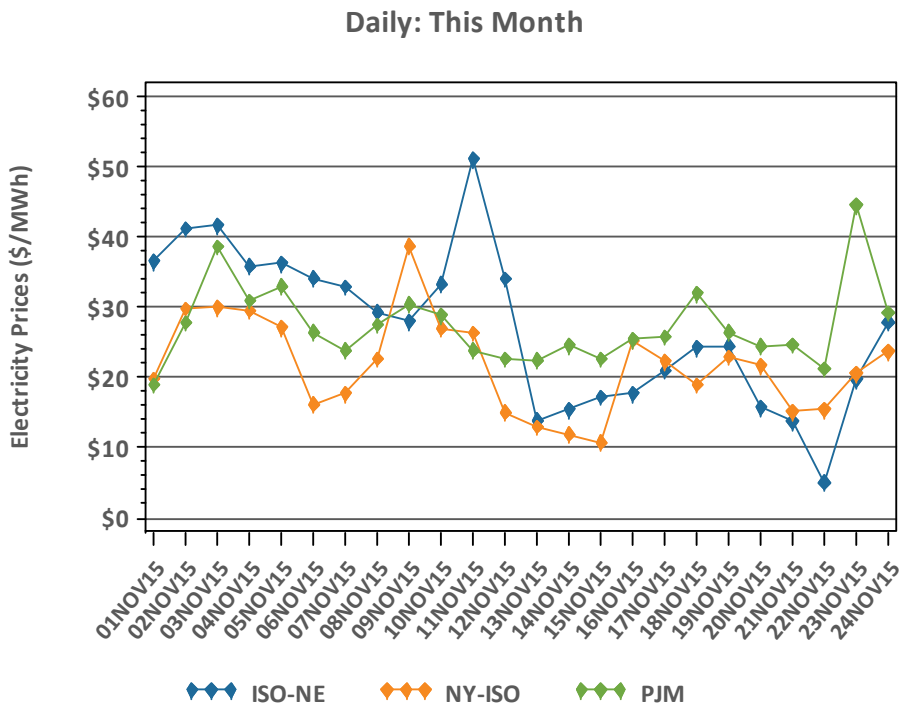
Underlying natural gas data furnished by:

ice Global markets in clear view

New England, NY, and PJM Real Time Prices

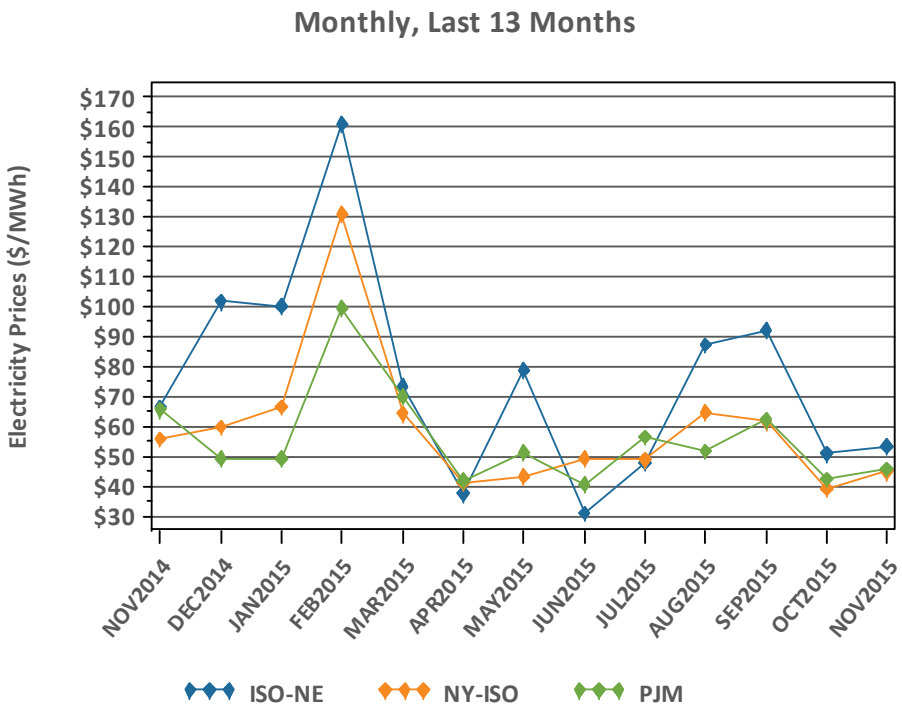


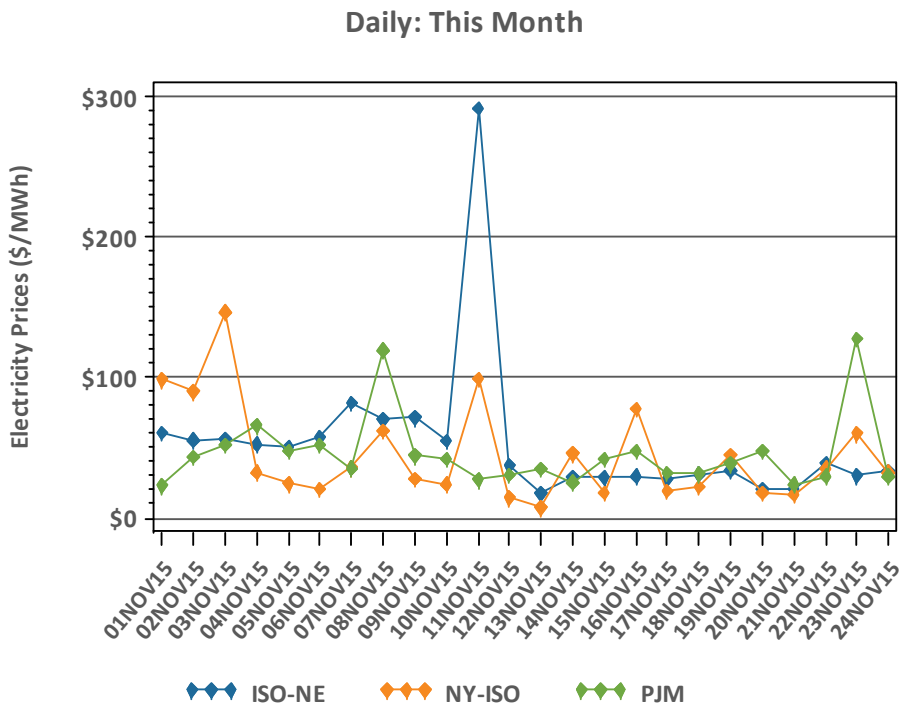
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Real Time Prices (Peak Hour)





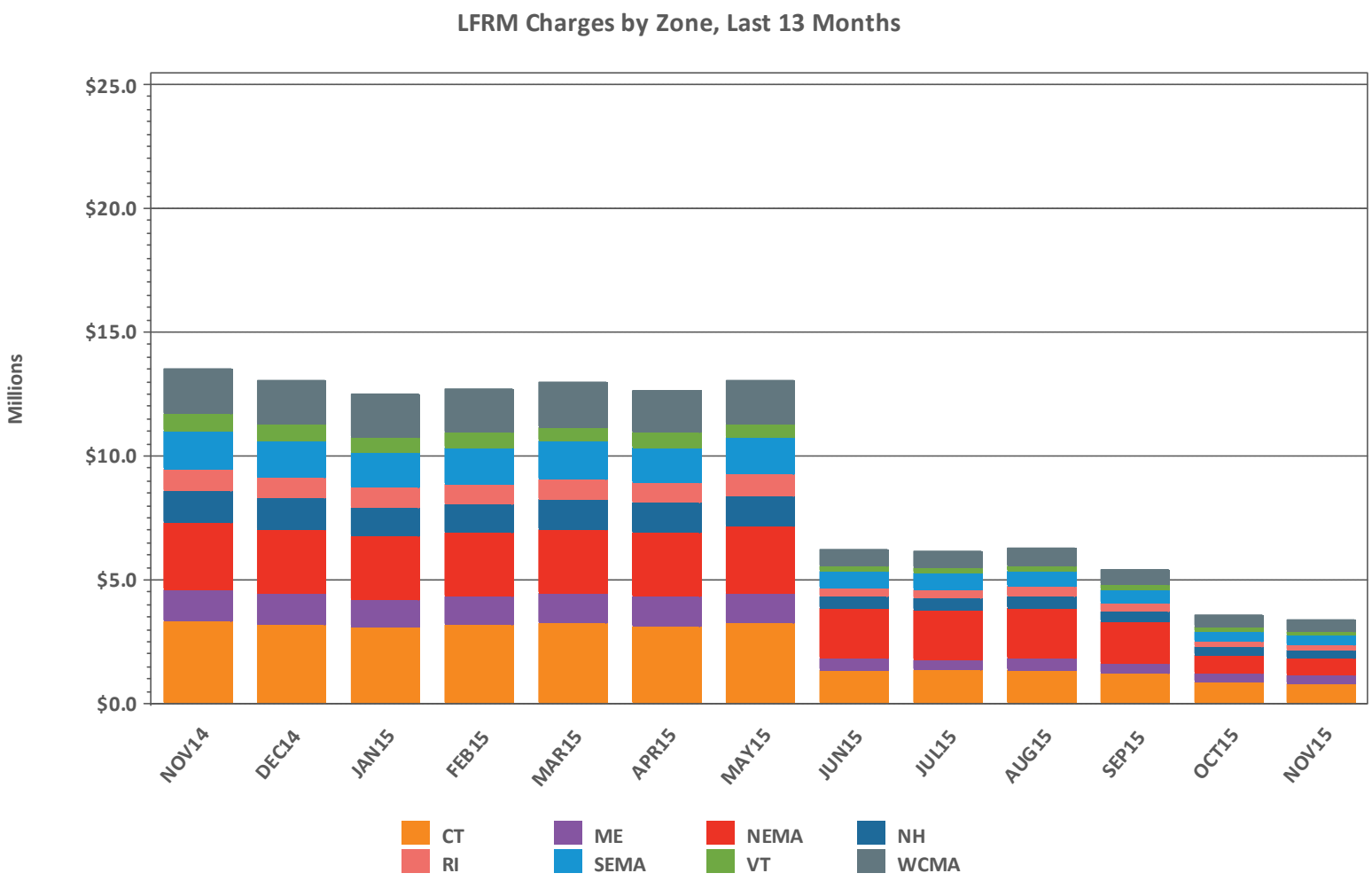
*Forecasted New England peak hour is reflected.

Reserve Market Results – November 2015

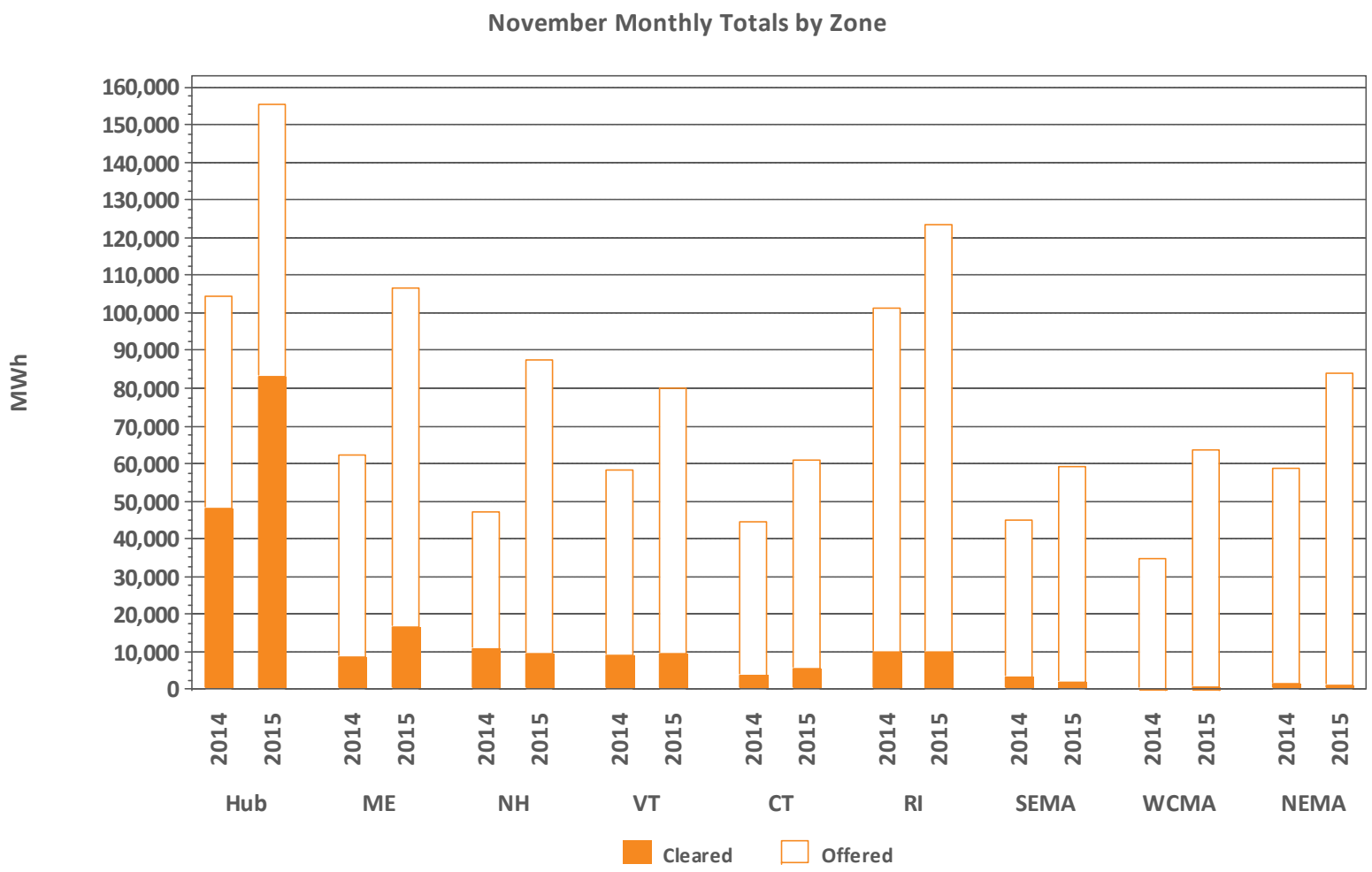
- Maximum potential Forward Reserve Market payments of $3.5M were reduced by credit reductions of $65K, failure-to-reserve penalties of $103K and failure-to-activate penalties of $2K, resulting in a net payout of $3.4M or 95% of maximum
  - Rest of System: $1.62M/$1.73M (94%)
  - Southwest Connecticut: $0.28M/$0.31M (89%)
  - Connecticut: $1.46M/$1.49M (98%)
- $580K total Real-Time credits were reduced by $269K in Forward Reserve Energy Obligation Charges for a net of $310K in Real-Time Reserve payments
  - Rest of System: 28 hours, $188K
  - Southwest Connecticut: 28 hours, $137K
  - Connecticut: 28 hours, -$41K
  - NEMA: 28 hours, $26K

* "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market.

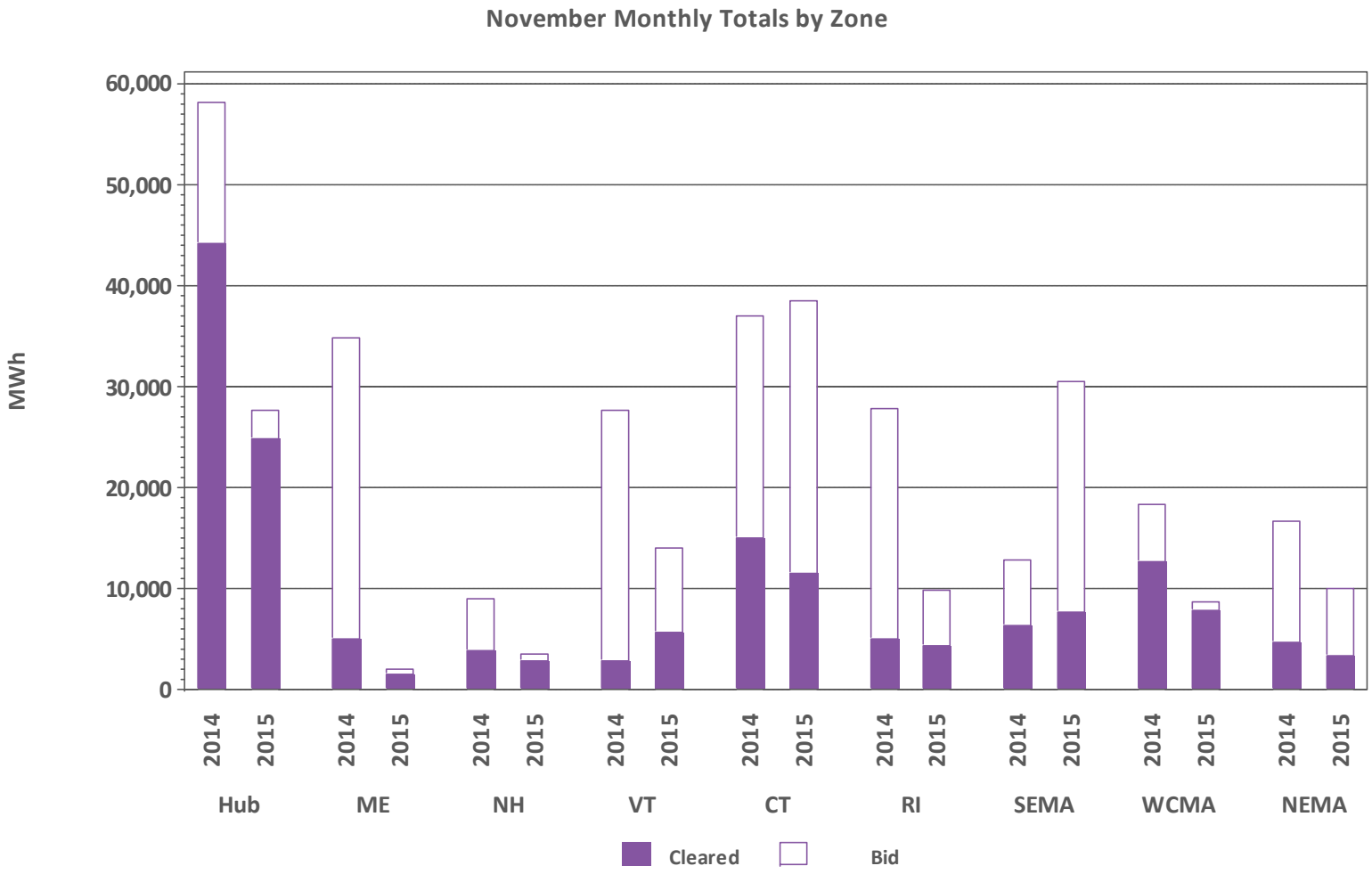
LFRM Charges to Load by Load Zone ($)



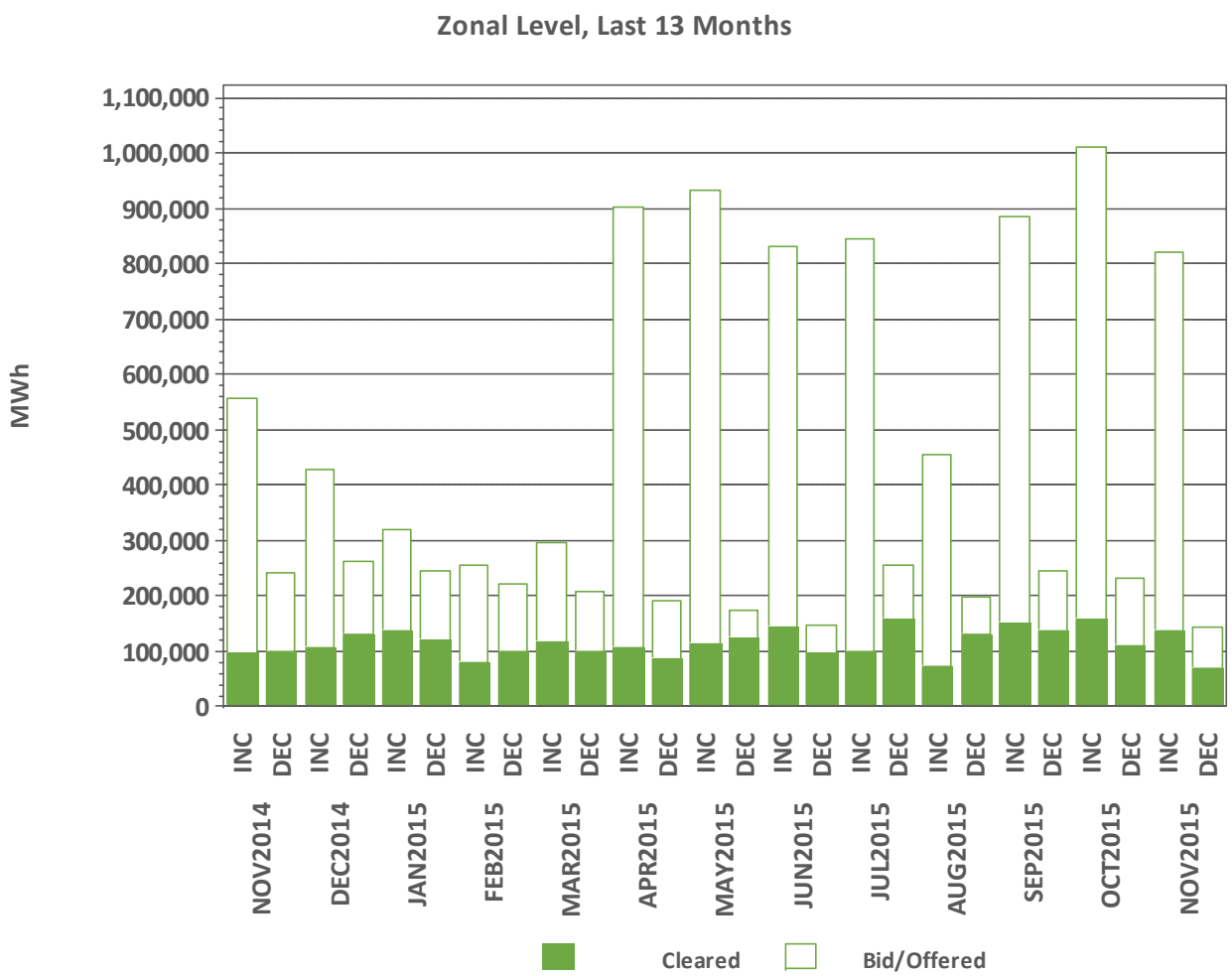
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

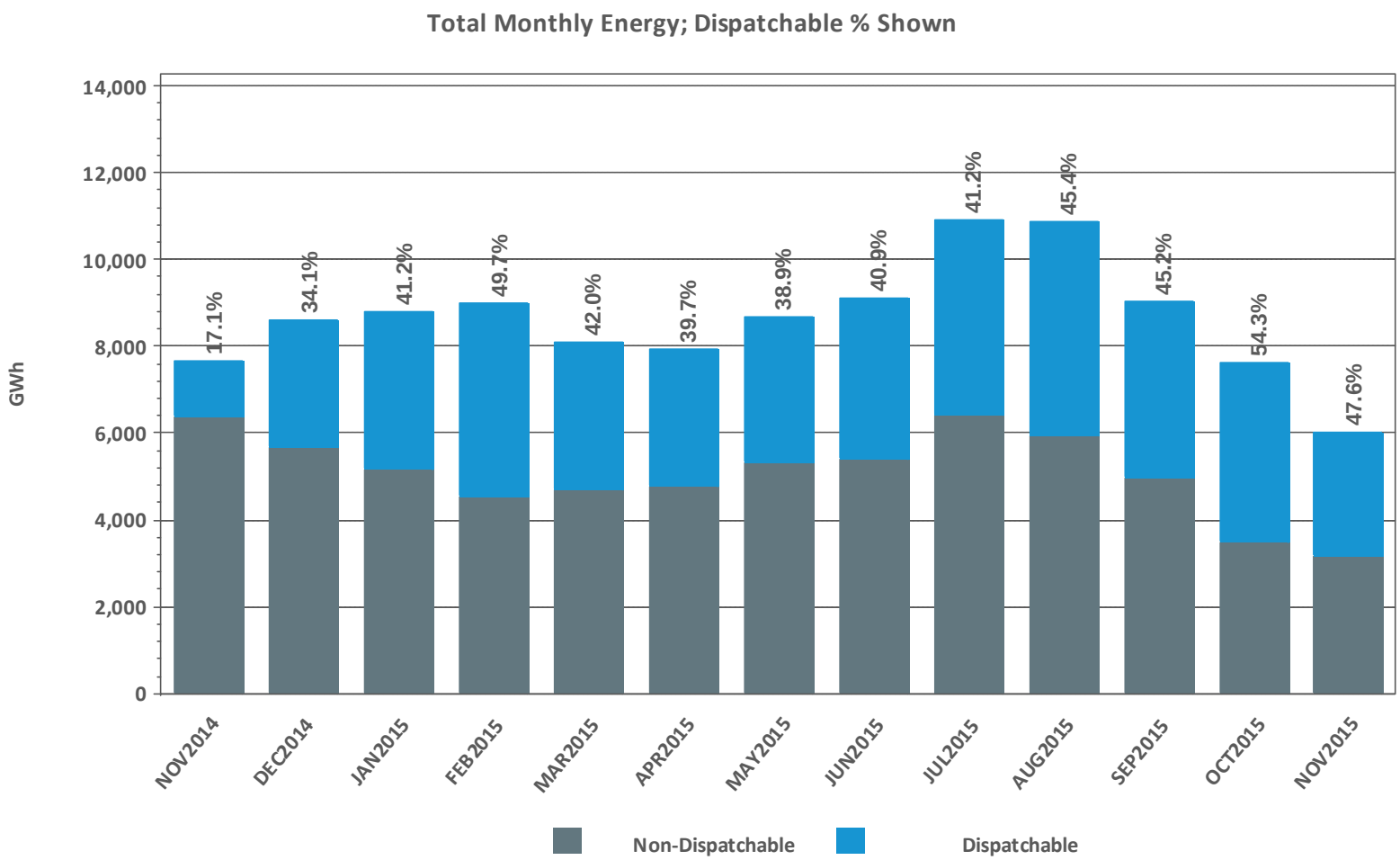


Total Increment Offers and Decrement Bids



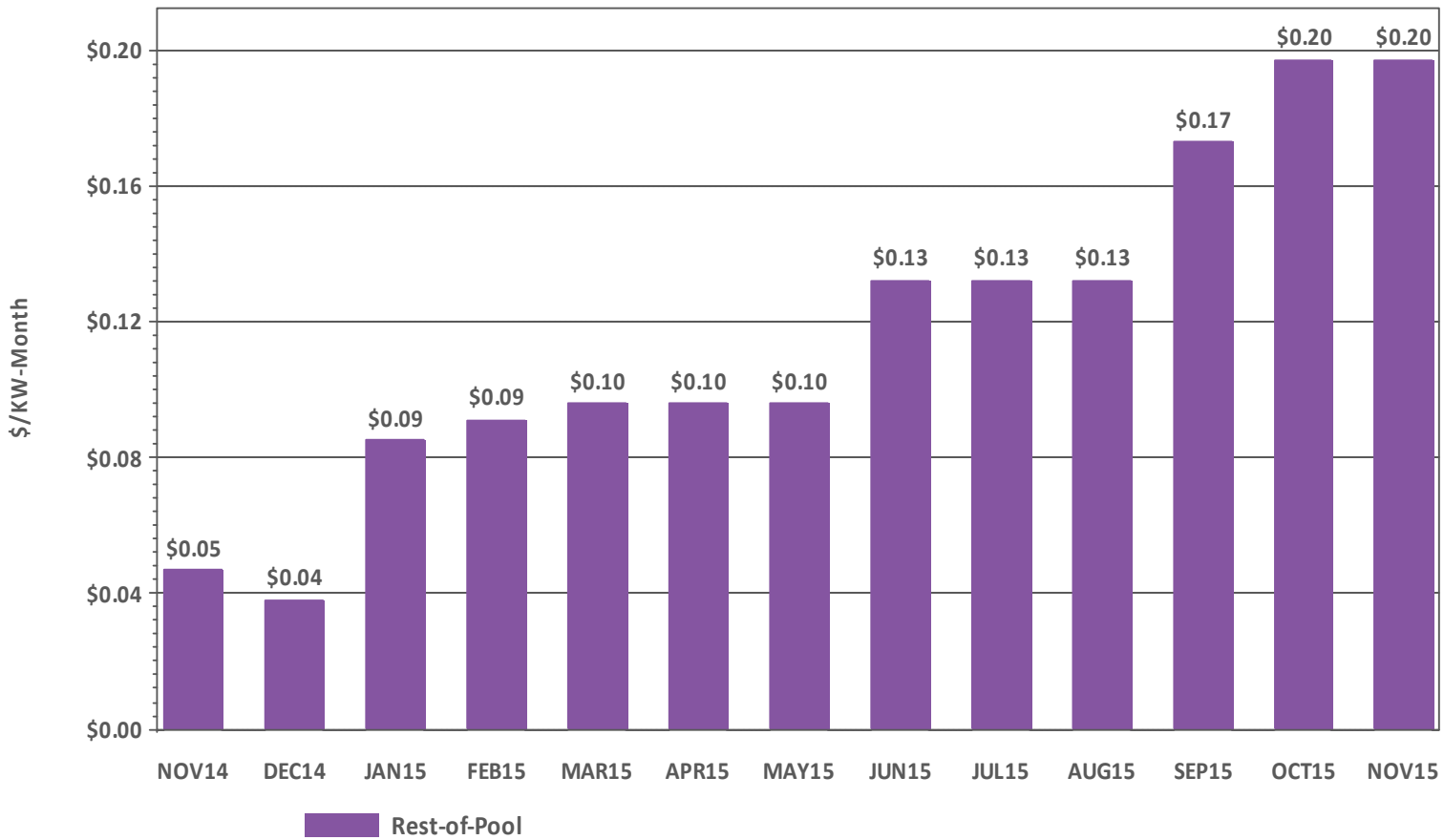
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).

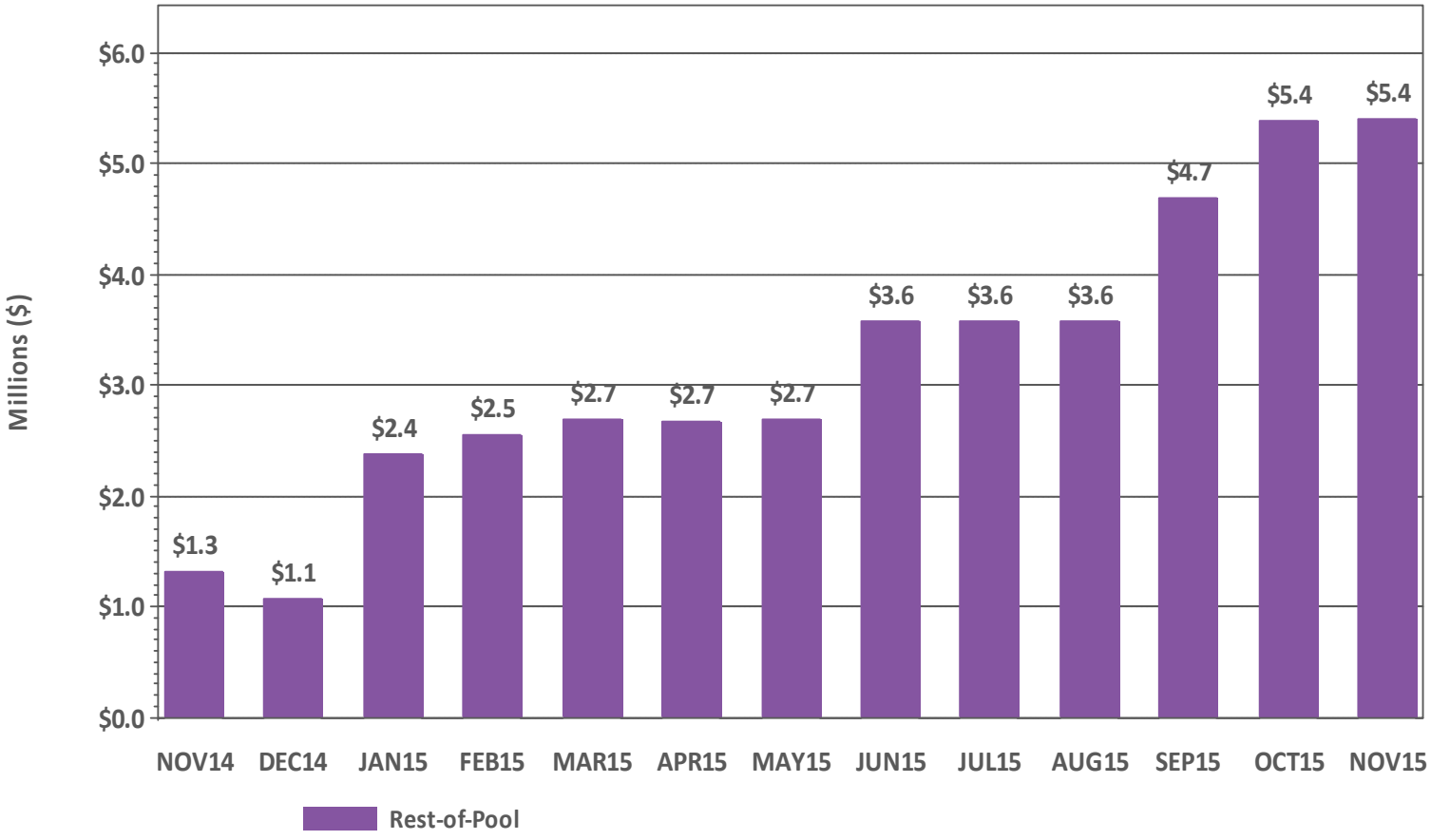
Rolling Average Peak Energy Rent (PER)



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.

PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.

REGIONAL SYSTEM PLAN (RSP)

RSP15 and the RSP Process

- ISO Board of Directors approved RSP15 on November 5
  - The ISO appreciates all the stakeholder effort and input that made this report possible
- On October 27, the TC discussed proposed changes to the OATT, including Attachment K, in response to stakeholder requests
  - Issue RSP no less than once every three years
  - It is the ISO's intent to issue the next RSP in 2017, pending further input from stakeholders, and to issue RSP every other year
  - Change the timing of the RSP page turn, public meeting, and issuance from specific months to more generic requirements would better coordinate with stakeholder schedules, ISO workloads, and the processes of neighboring systems
  - Follow-up discussion with the TC will be scheduled and a vote is anticipated 4th quarter

Planning Advisory Committee (PAC)

- December PAC Meeting Agendas (tentative)
  - December 14
    - Offshore SEMA Wind Economic Study Update
    - Maine Wind Economic Study Update
    - Keene Road Economic Study Update
    - Transmission Planning Assumptions
  - December 15
    - Technical Session – FCM Overlapping Impact Analysis and the Queue

Distributed Generation Forecast Working Group (DGFWG)

- DGFWG meeting is scheduled for December 8 to discuss updates to state DG policies, recent DG survey results, and next steps
- ISO is surveying utilities on a monthly basis for total PV capacity by service territory in support of operational load forecasting activities
- ISO will continue to work with DGFWG stakeholders to improve data collection processes
- ISO is working with DG resources seeking participation in the FCM
- ISO is working with the transmission owners, distribution owners, the states, and IEEE to resolve interconnection issues
- ISO will continue participation in DOE projects that support operational and planning forecasts of PV

Environmental Matters

- Environmental Advisory Group teleconference held November 3 discussed the following:
  - Draft results of the 2014 New England Electric Generator Air Emissions Report
  - Mercury & Air Toxics Standard legal review
  - 2015 Ozone Standard and impacts on southern New England
  - EPA final Clean Power Plan and possible regional compliance strategies
  - Other environmental matters

Economic Studies

- ISO is conducting three 2015 economic studies of wind integration scenarios
  - Study of the Keene Road Area
  - Study utilizing the Strategic Transmission Analysis results
  - Study of offshore wind expansion
- Studies have been given priority by the ISO
  - Draft results for the Keene Road Area will be discussed with the PAC on December 15
  - Discussions of other draft results are planned for PAC by early 2016
  - Final reports completed after consultation with the PAC
- Studies will compare the performance of the future system with additional representative future system improvements
  - Studies will not include detailed transmission planning analysis including system impact study results
- ISO may form special economic study working groups that will supplement PAC discussions via conference calls
  - PAC presentations will be structured to discuss the general PAC economic study issues upfront
  - More technical discussions will be reviewed with PAC members as the last meeting agenda item

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

Connecticut River Valley

Status as of 11/24/15

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	Oct-17	1
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Oct-17	1
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Oct-17	1
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	1

Note: The above listing focuses on major transmission line construction and rebuilding.

NEEWS: Interstate Reliability Project

Status as of 11/24/15

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

Upgrade	Expected In-Service	Present Stage
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	4
Card 345 kV Substation Expansion	Dec-15	4
Lake Road 345 kV Substation Expansion	Dec-15	3
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	3
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	3
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	3
New Sherman Road 345 kV Substation	Dec-15	3
West Farnum 115 kV Substation Upgrades	Sep-14	4
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	3
Riverside Substation Relay Upgrades	Sep-14	4
Woonsocket Substation Relay Upgrades	Sep-14	4
Hartford Avenue Substation Relay Upgrades	Sep-14	4
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	3
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	3
Millbury 3 Substation Expansion	Dec-15	3
Carpenter Hill Substation Relay Upgrades	Dec-15	3

New Hampshire/Vermont 10-Year Upgrades

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	3
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Dec-16	2
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-17	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	3

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Dec-16	3
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 11/24/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	4*
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Dec-16	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	1
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Dec-17	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	3
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	2
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	2
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-16	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	2
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-18	2
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	2
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	2
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	2
Add a new 115 kV line from Frost Bridge to Campville	Dec-18	2
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	2
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	2
Add a new 345/115 kV autotransformer at Barbour Hill substation	Jan-16	3
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Jan-16	3
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	2

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-16	2
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	1
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	2
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-17	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-17	1
Loop the 1990 line in and out the Bunker Hill substation	Dec-17	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-18	1
Loop the 1570 line in and out the Pootatuck substation	Dec-18	1
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	3

Southwest Connecticut Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-18	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-17	1

Southwest Connecticut Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-17	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	2
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4*
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-16	1
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	3
Upgrade the 115 kV bus at the Baird substation	Dec-17	2
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	3
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-19	1

Southwest Connecticut Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-Service	Present Stage
Remove the Sackett phase shifter	Dec-17	1
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-17	2
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-17	2
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-16	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	3
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	1
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	1
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	3
Reconductor the F-158S 115 kV line from Maplewood to Everett	Dec-16	1
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Dec-18	1
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	3
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-16	1

Greater Boston Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Separate X-24 and E-157W DCT	May-17	1
Separate Q-169 and F-158N DCT	Dec-15	3
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	2
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	May-17	1
Install third 115 kV line from West Walpole to Holbrook	Dec-16	1
Install new 345 kV breaker in series with the 104 breaker at Stoughton	Dec-16	2
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-15	3
Install a new 115 kV line from Sudbury to Hudson	Dec-18	1

Greater Boston Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-17	1
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-16	1
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	May-16	2
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Dec-15	3
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	2
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	Dec-16	2
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Dec-16	1
Install a 115 kV breaker on the West bus at K Street	Dec-16	2
Install 115 kV cable from Mystic to Chelsea	Dec-17	1
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-17	1

Greater Boston Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-17	1
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station	Dec-16	1
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-17	1
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-17	2

Greater Boston Projects, cont.

Status as of 11/24/15

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Jun-16	2
Upgrade Edgar 115 kV station to BPS standards	Dec-20	1
Upgrade Dover 115 kV station to BPS standards	Dec-20	1
Upgrade East Cambridge 115 kV station to BPS standards	Dec-19	1
Upgrade West Methuen 115 kV station to BPS standards	Jun-18	1
Upgrade Medway 115 kV station to BPS standards	Dec-19	2
Install a 200 MVAR STATCOM at Coopers Mills	Dec-18	1
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	1
Install a 345 kV 160 MVAR shunt reactor at K Street	May-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Jun-17	2
Install a 115 kV breaker in series with the 29 breaker at K Street	Dec-16	2

Pittsfield/Greenfield Projects

Status as of 11/24/15

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Sep-16	2
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Dec-16	2
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Dec-16	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Dec-16	3
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Dec-16	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	3

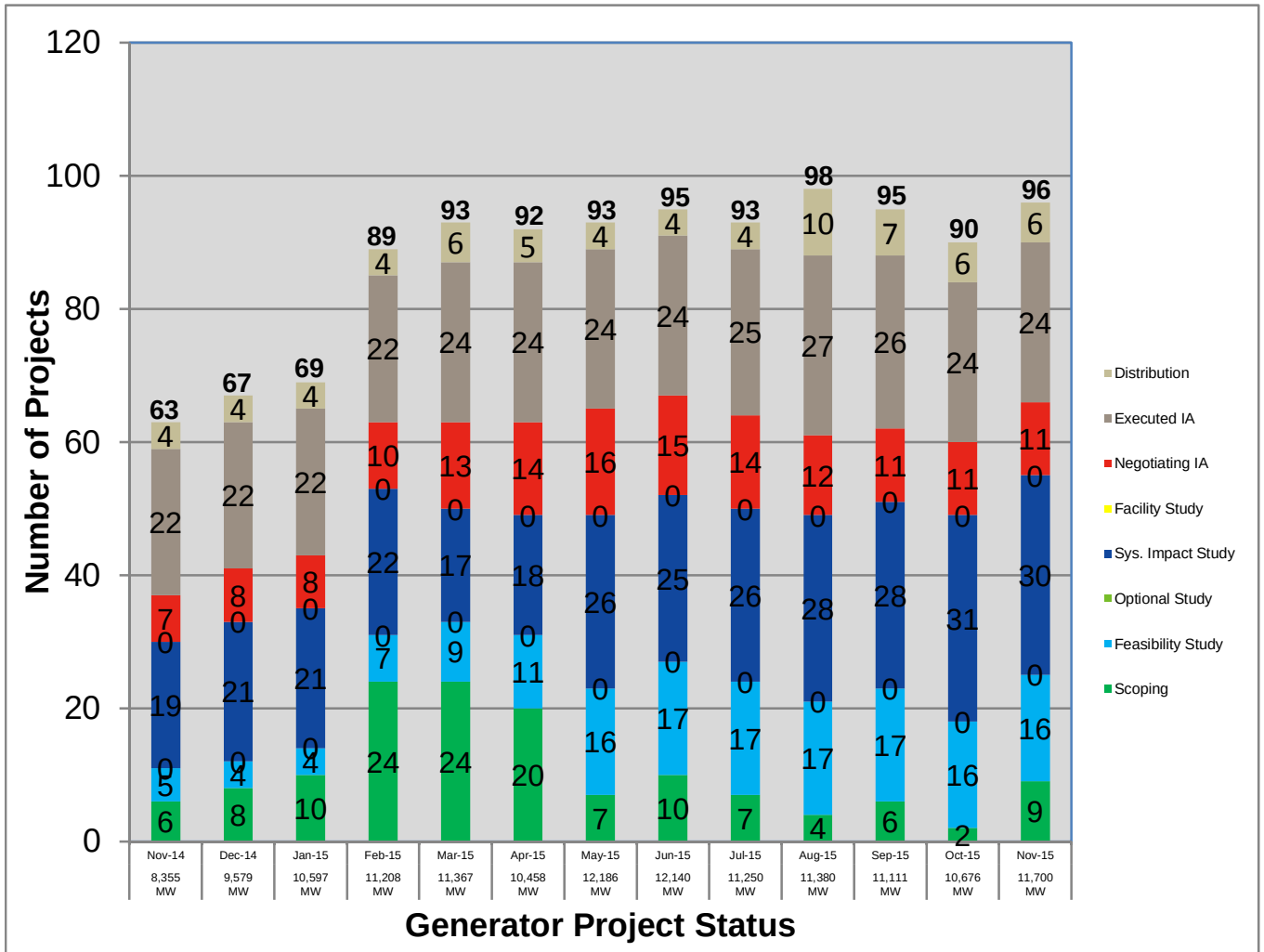
Pittsfield/Greenfield Projects, cont.

Status as of 11/24/15

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	3
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Oct-16	2
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

Status of Tariff Studies



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Note: As of November 2015, there are 7 ETU's in SIS and 2 in scoping
Note: November 2015 based on data as of November 23

OPERABLE CAPACITY ANALYSIS

Winter 2015-16 Analysis

Winter 2015-16 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2016[2] CSO	January - 2016[2] SCC
Generator Operable Capacity MW [1]	29,897	32,814
OP CAP From OP-4 RTDR (+)	413	413
OP CAP From OP-4 RTEG (+)	174	174
Operable Capacity Generator with OP-4 DR and RTEG	30,484	33,401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,226	1,226
Non Commercial Capacity (+)	35	35
Non Gas-fired Planned Outage MW (-)	686	729
Gas Generator Outages MW (-)	0	34
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	3,828	4,220
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,431	26,879
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,077	21,077
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,382	23,382
Operable Capacity Margin [3]	1,049	3,497

[1] Generator Operable Capacity is based on data as of **November 10, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **November 10, 2015**

[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **January 9, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2015-16 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January- 2016[2] CSO	January - 2016[2] SCC
Generator Operable Capacity MW [1]	29,897	32,814
OP CAP From OP-4 RTDR (+)	413	413
OP CAP From OP-4 RTEG (+)	174	174
Operable Capacity Generator with OP-4 DR and RTEG	30,484	33,401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,226	1,226
Non Commercial Capacity (+)	35	35
Non Gas-fired Planned Outage MW (-)	686	729
Gas Generator Outages MW (-)	0	34
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	4,534	5,004
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,725	26,095
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,737	21,737
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,042	24,042
Operable Capacity Margin [3]	(317)	2,053

[1] Generator Operable Capacity is based on data as of **November 10, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **November 10, 2015**

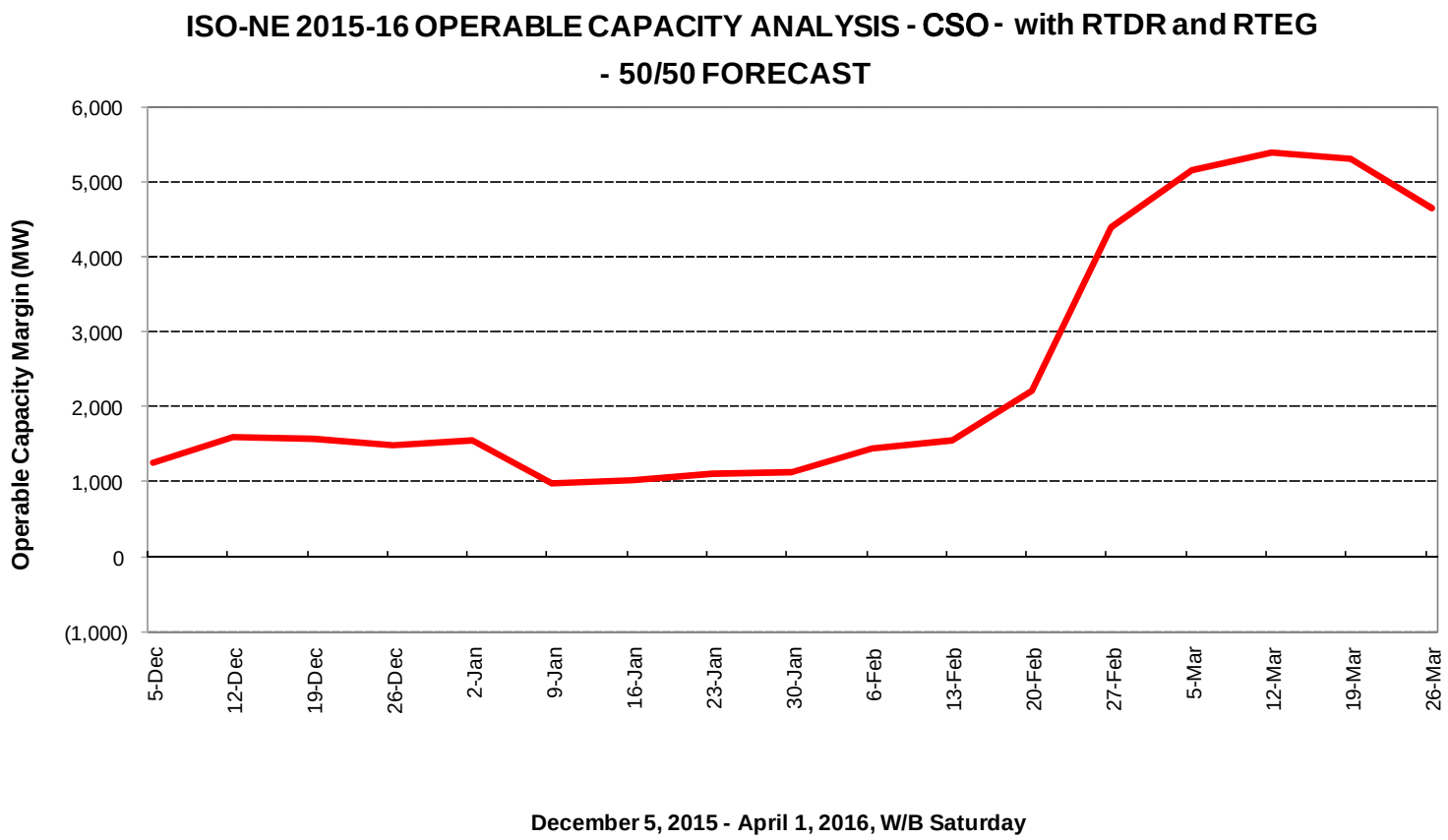
[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **January 9, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

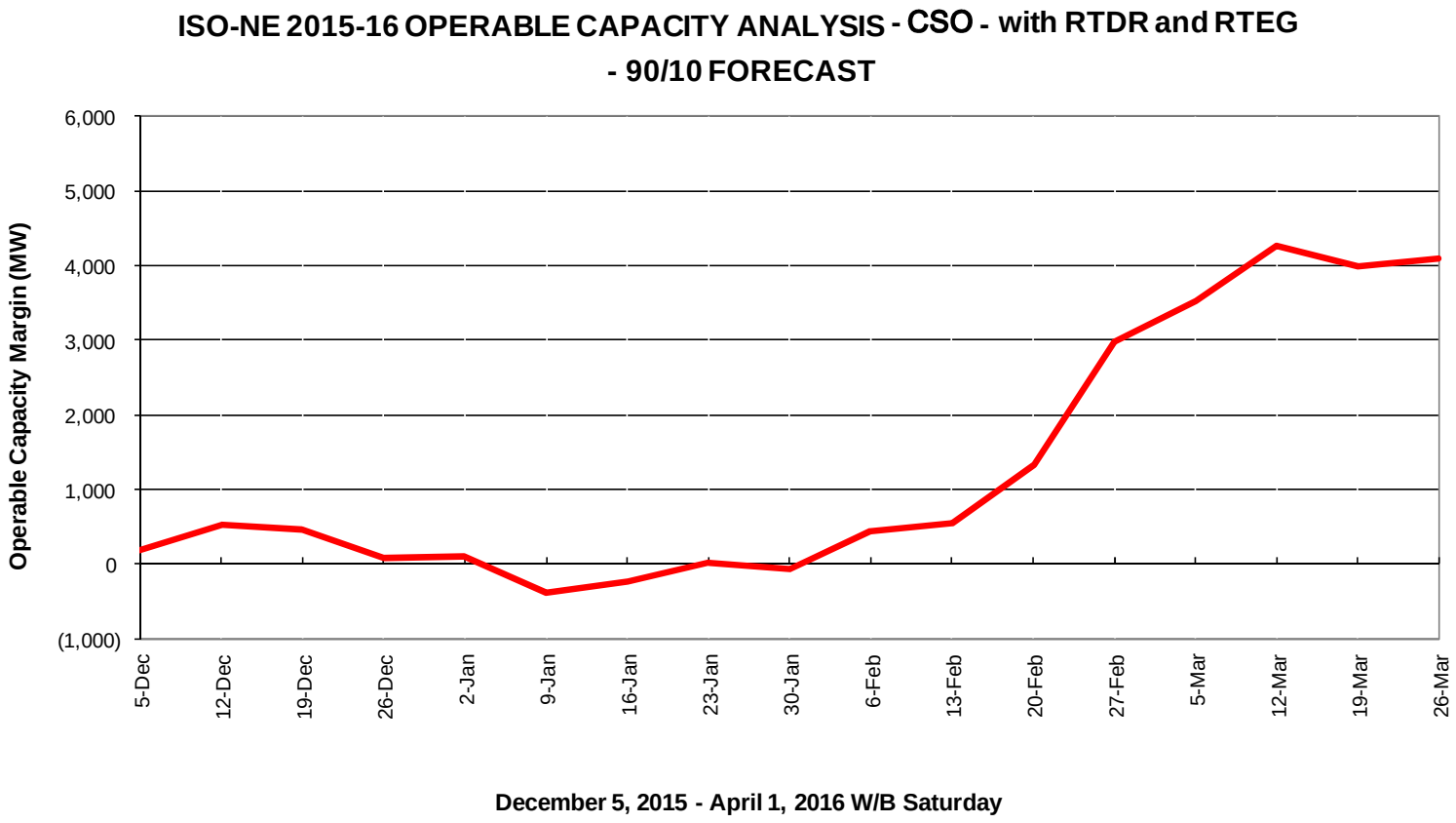
[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2015-16 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2015-16 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



Winter 2015-16 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2015-16 OPERABLE CAPACITY ANALYSIS

December 4, 2015 - 50/50 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
12/5/2015	30,428	867	30	1,537	1,250	3,200	2,188	23,150	19,951	2,305	22,256	894	284	1,178	142	1,320
12/12/2015	30,428	867	30	849	900	3,200	2,581	23,795	20,247	2,305	22,552	1,243	284	1,527	142	1,669
12/19/2015	30,428	867	30	831	654	3,200	2,870	23,770	20,258	2,305	22,563	1,207	284	1,491	142	1,633
12/26/2015	30,428	867	35	712	161	3,200	3,494	23,763	20,322	2,305	22,627	1,136	284	1,420	142	1,562
1/2/2016	29,897	1,226	35	685	0	2,800	3,741	23,932	20,602	2,305	22,907	1,025	413	1,438	174	1,612
1/9/2016	**29,897**	**1,226**	**35**	**686**	**0**	**2,800**	**3,828**	**23,844**	**21,077**	**2,305**	**23,382**	**462**	**413**	**875**	**174**	**1,049**
1/16/2016	29,897	1,226	35	643	0	2,800	3,828	23,887	21,077	2,305	23,382	505	413	918	174	1,092
1/23/2016	29,897	1,226	35	610	0	2,800	3,785	23,963	21,077	2,305	23,382	581	413	994	174	1,168
1/30/2016	29,897	1,226	35	642	0	3,100	3,655	23,761	20,850	2,305	23,155	606	413	1,019	174	1,193
2/6/2016	29,897	1,226	35	685	0	3,100	3,568	23,805	20,577	2,305	22,882	923	413	1,336	174	1,510
2/13/2016	29,897	1,226	35	700	0	3,100	3,481	23,877	20,547	2,305	22,852	1,025	413	1,438	174	1,612
2/20/2016	29,897	1,226	35	381	0	3,100	3,394	24,283	20,279	2,305	22,584	1,699	413	2,112	174	2,286
2/27/2016	29,897	1,226	37	794	0	2,200	2,715	25,451	19,269	2,305	21,574	3,877	413	4,290	174	4,464
3/5/2016	29,897	1,226	37	850	1,147	2,200	1,115	25,848	18,912	2,305	21,217	4,631	413	5,044	174	5,218
3/12/2016	29,897	1,226	37	1,271	1,324	2,200	486	25,879	18,712	2,305	21,017	4,862	413	5,275	174	5,449
3/19/2016	29,897	1,226	37	2,618	917	2,200	0	25,425	18,339	2,305	20,644	4,781	413	5,194	174	5,368
3/26/2016	29,897	1,226	37	3,024	1,239	2,700	0	24,197	17,762	2,305	20,067	4,130	413	4,543	174	4,717

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 and generator improvements 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. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
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 2015 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net 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. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2015-16 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2015-16 OPERABLE CAPACITY ANALYSIS

December 4, 2015 - 90/10 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
12/5/2015	30,428	867	30	1,537	1,250	3,200	2,627	22,711	20,579	2,305	22,884	(173)	284	111	142	253
12/12/2015	30,428	867	30	849	900	3,200	3,022	23,354	20,883	2,305	23,188	166	284	450	142	592
12/19/2015	30,428	967	30	831	654	3,200	3,427	23,313	20,895	2,305	23,200	113	284	397	142	539
12/26/2015	30,428	867	35	712	161	3,200	4,260	22,997	20,960	2,305	23,265	(268)	284	16	142	158
1/2/2016	29,897	1,226	35	685	0	2,800	4,534	23,139	21,248	2,305	23,553	(414)	413	(1)	174	173
1/9/2016	**29,897**	**1,226**	**35**	**686**	**0**	**2,800**	**4,534**	**23,138**	**21,737**	**2,305**	**24,042**	**(904)**	**413**	**(491)**	**174**	**(317)**
1/16/2016	29,897	1,226	35	643	0	2,800	4,421	23,294	21,737	2,305	24,042	(748)	413	(335)	174	(161)
1/23/2016	29,897	1,226	35	610	0	2,800	4,194	23,554	21,737	2,305	24,042	(488)	413	(75)	174	99
1/30/2016	29,897	1,226	35	642	0	3,100	4,194	23,222	21,503	2,305	23,808	(586)	413	(173)	174	1
2/6/2016	29,897	1,226	35	685	0	3,100	3,922	23,451	21,222	2,305	23,527	(76)	413	337	174	511
2/13/2016	29,897	1,226	35	700	0	3,100	3,832	23,526	21,192	2,305	23,497	29	413	442	174	616
2/20/2016	29,897	1,226	35	381	0	3,100	3,652	24,025	20,916	2,305	23,221	804	413	1,217	174	1,391
2/27/2016	29,897	1,226	37	794	0	2,200	3,517	24,649	19,877	2,305	22,182	2,467	413	2,880	174	3,054
3/5/2016	29,897	1,226	37	850	1,147	2,200	2,135	24,828	19,509	2,305	21,814	3,014	413	3,427	174	3,601
3/12/2016	29,897	1,226	37	1,271	1,324	2,200	1,021	25,344	19,303	2,305	21,608	3,736	413	4,149	174	4,323
3/19/2016	29,897	1,226	37	2,618	917	2,200	725	24,700	18,920	2,305	21,225	3,475	413	3,888	174	4,062
3/26/2016	29,897	1,226	37	3,024	1,239	2,700	0	24,197	18,325	2,305	20,630	3,567	413	3,980	174	4,154

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. New resources and generator improvements that have acquired a CSO but have not become commercial.
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8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
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10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% the second largest contingency.
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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. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16) This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4:Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	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.	0 [1] 600
2	Dispatch real time Demand Resources.	**December 284[3]** **January - March 413[3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	135 [4] **December 142[3]** **January - March 174 [3]**

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 10, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	269 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**December 2,975 MW** **January - March 3,136 MW**

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 10, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 4, 2015

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2016

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 2016 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 2016 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	Thomas W. Kaslow
Vice-Chair	John J. Keene Jr.
Vice-Chair	Donald J. Sipe
Secretary	David T. Doot
Assistant Secretary	Paul N. Belval

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Kenneth Dell Orto, Chairman, NEPOOL Budget and Finance Subcommittee
Paul Belval, NEPOOL Counsel

DATE: November 25, 2015

RE: Estimated Budget for 2016 Participant Expenses

The Participants Committee will be asked at its December 4 meeting to approve the estimated NEPOOL expense budget for 2016, which is attached to this memorandum (the "2016 Budget"). As we did in prior years, we have prepared the 2016 Budget to compare the estimated expenses for 2016 to both the estimated 2015 expenses approved by the Participants Committee in December 2014 and the current forecast for actual expenses for 2015 (Attachment A).

The 2016 Budget reflects a decrease in NEPOOL expenses from the 2015 budget, due primarily to the expected elimination of the Review Board by the 129th Agreement Amending New England Power Pool Agreement, which is pending before the FERC and is expected to become effective on January 1, 2016. We have also attached a calculation of the per-Participant share of the 2016 Budget expenses, comparing that amount to the same figures from five years ago, which generally shows a slight reduction in 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 2016 Budget. At its November 19 teleconference, the Subcommittee discussed the proposed 2016 Budget and recommended its adoption without objection.

The following form of resolution may be used in acting on the 2016 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2016 as presented at this meeting.

ATTACHMENT A

ESTIMATED 2016 NEPOOL BUDGET COMPARED TO 2015 NEPOOL BUDGET AND 2015 PROJECTED ACTUAL EXPENSES

Line Items	2016 Proposed Budget	2015 Approved Budget	2015 Current Forecast
NEPOOL Counsel Fees (1)	$3,700,000	$3,700,000	$3,500,000
NEPOOL Counsel Disbursements (1)	$ 55,000	$ 55,000	$ 55,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 45,000	$ 43,000
Committee Meeting Expenses (3)	$ 625,000	$ 650,000	$ 595,000
Review Board Compensation (4)	$ ---	$ 108,000	$ 108,000
Review Board Administrative and Support Expense (4)	$ ---	$ 20,000	$ 20,000
Generation Information System (3)	$1,095,000	$1,200,000	$1,086,000
Credit Insurance Premium (3)	$ 400,000	$ 450,000	$ 400,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (5)	$ 64,000	$ 75,000	$ 11,000
SUBTOTAL EXPENSES	$5,984,000	$6,303,000	$5,818,000
Revenue			
NEPOOL Membership Fees (3) (6)	($1,856,000)	($1,834,000)	($1,897,000)
Generation Information System (3) (7)	($1,095,000)	($1,200,000)	($1,086,000)
Credit Insurance Premium (3) (8)	($ 400,000)	($ 450,000)	($ 400,000)
TOTAL REVENUE	($3,351,000)	($3,484,000)	($3,383,000)
TOTAL NEPOOL EXPENSES	**$2,633,000**	**$2,819,000**	**$2,435,000**

Notes

(1) 2016 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2016 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2016 proposed estimate provided by ISO New England Inc. ("ISO").

(4) The Review Board was eliminated by the 129th Agreement Amending New England Power Pool Agreement, which is expected to become effective on January 1, 2016. The Participants are considering whether to identify an alternative dispute resolution mechanism for disputes related to Markets Committee or Participants Committee actions related to the NEPOOL Generation Information System, but no decision has been made with respect to such a mechanism.

(5) The NEPOOL Participants Committee approved a total budget of $75,000 for the NAMS Consultant at its June 5, 2015 meeting. William Dunn was retained as the NAMS Consultant to participate in the ongoing ISO operational audit process. Mr. Dunn is expected to complete his work in 2016, and the total budget approved by the NPC will cover that work in both 2015 and 2016.

(6) The 2016 proposed estimate is based on the 2015 actual receipts through October 2015, plus a forecast (a) for new members, of 3 members at $5,000 each, 2 members at $1,000 each, 4 members at $500 each, and (b) for terminated members, of 4 at $5,000 each, 2 at $1,250 each, and 5 at $500 each.

(7) 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.

(8) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy.

ATTACHMENT B

ESTIMATED BREAKDOWN OF PROJECTED 2016 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2016 figures assume no change in current NEPOOL membership)
(2011 figures as projected and budgeted at 2010 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2016	**2011**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**4,489,000**	**4,693,100**
B.	Projected NEPOOL Membership Fees	**1,856,000**	**1,910,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**2,633,000**	**2,783,100**
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 2016 is based on 2014 peak loads of MPEU members)	**42,335**	**65,580**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2015 is estimated amount based on 2014 membership data)	**60,041**	**53,716**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C x 2% x lrg_y)	**210,640**	**222,648**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors ("Remaining Sectors") (C – (D + E + F+ G))	**2,319,984**	**2,441,156**
CALCULATION OF SECTOR ALLOCATIONS			
		2016	**2011**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**579,996**	**610,289**
J.	Total Amount paid by Related Person Suppliers (2 voting members) (I ÷ s_y) x rps_y	**9,431**	**10,614**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,361,201**	**1,432,612**

L.	Total Amount of Provisional Generation Share shared equally by Generation Sector Provisional Members $(0.02 \div gprov_y \times K) \times (g_y \div (g_y + (s_y - rps_y) + lrg_y))$	**n/a**	**909**
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 $((K - L) \div (g_y + (s_y - rps_y) + lrg_y))$	**9,936**	**10,684**
N.	Transmission Sector Share per full voting member[ii] $((N-O) \div t_y)$	**96,666**[ii]	**86,312**
O.	Provisional Transmission Sector member share $(I \times (tprov_y \times 0.005))$	**n/a**	**6,103**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[1] $(I \div poe_y)$	**10,175**[i]	**11,515**[i]

ANNUAL VARIABLES			
		2016	**2011**
s_y	# Supplier Sector voting members	123	115
rps_y	# Supplier Sector Related Person Suppliers	2	2
g_y	# Generation Sector voting members	12	17
$gprov_y$	# Generation Sector provisional group members	0	1
lrg_y	# AR Sector Large Renewable Generation Resource Providers	4	4
t_y	# Transmission Sector voting members	6[ii]	7
$tprov_y$	# Transmission Sector provisional group members	0	2
poe_y	# Publicly Owned Entity members	57	53

[i] A number of Publicly Owned Entity Sector members share Participant Expenses pursuant to an agreed-upon allocation percentage. The member share noted in the table is indicative of the share a Publicly Owned Entity, which does not participate in the group arrangement, would pay.

[ii] The individual TO Share will increase to $115,999 if CMP and UI become Related Persons at the end of 2015 as expected.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: November 25, 2015

RE: Proposed FCM Resource Retirement Reforms

At its December 4, 2015 meeting, the Participants Committee will be asked to consider supporting a number of revisions to the Forward Capacity Market (FCM) rules related to resource retirements, as proposed by the ISO and ISO's Internal Market Monitor (IMM) (the Resource Retirement Reforms). This memorandum provides an overview of the Resource Retirement Reforms and also discusses potential Participant-sponsored amendments to this proposal.

By way of brief background, the IMM has identified concerns it has with respect to the market impact of resource retirements under the current FCM rules. To address its concerns, the IMM has proposed to replace the current Non-Price Retirement Request mechanism with a requirement for the submission of a priced Retirement De-List Bid (along with adjustments to the Permanent De-List Bid). Under this new retirement process, Market Participants would submit a Permanent or Retirement De-List Bid, and upon receiving a retirement determination notification, choose from the following options:

a) Using the IMM/FERC-accepted price as the Permanent or Retirement De-List Bid: Resource would retire if the bid clears in the FCA or, alternatively, would receive a Capacity Supply Obligation (CSO) if the bid did not clear at the IMM/FERC-accepted price, regardless of whether the Bid submitted by the Market Participant was higher than the IMM/FERC-accepted price;
b) Unconditional retirement: Market Participant can unconditionally retire, but if the Participant fails a new IMM portfolio test, a proxy De-List Bid would be entered into the auction to mitigate market impact; or
c) Conditional retirement: Resource can leave the market at the Participant's submitted price if the clearing price in the FCA was less than or equal to the submitted bid (a proxy De-List Bid would be utilized to mitigate market impacts).

As part of the package of Resource Retirement Reforms, the ISO has also proposed to accelerate the timing of the resource retirement process in order to allow more opportunity for new resources to react to potential retirements of capacity. ISO proposes to do this by adopting a schedule that notifies the market of potentially retiring resources prior to when new resources must submit Show-of-Interest applications.[1]

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[1] Specifically, the Resource Retirement Reforms would modify certain FCA deadlines as follows: (1) the Show-of-Interest deadline would be moved from February to April; (2) the deadline for submittal of Permanent De-List Bids would be moved from June to March; and (3) the deadline for submittal of Retirement Requests would be moved from October to March. After these March deadlines,

Further detail on the proposed Resource Retirement Reforms are provided in the ISO's supporting materials included with this memorandum, which include a copy of all of the proposed Tariff revisions. Please note that the ISO's proposed changes it has submitted for vote by the Participants Committee differs somewhat from the changes considered by the Markets Committee at its November 18 meeting. The IMM has identified these changes and indicated that they are in response to feedback it has received from NEPOOL members, as explained in the attached memorandum from the ISO.

Stakeholder Process to Date

Portions of the proposed Resource Retirement Reforms were considered and voted separately by NEPOOL's three Technical Committees. The majority of the changes were vetted by the Markets Committee over a number of meetings, culminating in a series of votes taken at the November 18 Markets Committee meeting. The remainder of the proposed Tariff revisions, which are corresponding to those voted by the Markets Committee, were considered separately by the Reliability Committee and the Transmission Committee. Both Committees met on November 20 and voted on proposed revisions to their respective sections of the ISO-NE Tariff. More detailed information from each Committee is included below.

Agenda Item 9(a): Market Rule 1, Section 13, Appendix A of Market Rule 1, and Section I.2.2 (Definitions)

On November 18, the Markets Committee considered and failed to pass a resolution to recommend Participants Committee support for the Resource Retirement Reforms with a 57.01% Vote in favor.[2] Prior to the Markets Committee's vote on the ISO's proposal, nine motions to amend the main motion were considered. While seven failed to garner the requisite 60% Vote threshold required for Markets Committee support, one amendment was overwhelmingly supported and another withdrawn. A copy of the November 18, 2015 Notice of Actions of the Markets Committee detailing these votes is included with this memorandum as Attachment A.

Potential Motions to Amend the Resource Retirement Reforms

As indicated, nine motions to amend the proposed Resource Retirement Reforms were considered by the Markets Committee at its November 18 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 B):

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the ISO would publish information regarding the capacity resources seeking to permanently exit the market.

[2] The individual Sector votes consisting of the following: *Generation* - 0% in favor, 17.13% opposed; *Transmission* - 15.57% in favor, 1.56% opposed, 0.5 abstention; *Supplier* 0% in favor, 17.13% opposed, 7 abstentions; *Alternative Resources* – 7.19% in favor, 7.19% opposed, 1 abstention; *Publicly Owned Entity* – 17.13% in favor, 0% opposed; and End User - 17.13% in favor, 0% opposed.

A. *PSEG Proposed Amendments*

PSEG has indicated it may offer for Participants Committee consideration two motions to amend the Resource Retirement Reforms that were previously considered and failed to pass at the Markets Committee.

The first amendment (PSEG Amendment #1) would revise Section III.13.2.5.2.1 to permit a resource that submitted a priced retirement bid in a FCA and did not receive a CSO to participate in subsequent FCAs as an existing capacity resource. The second PSEG amendment (PSEG Amendment #2) would remove the binding nature of retirement bids from Section III.13.1.2.3.1 of Market Rule 1. Under PSEG Amendment #2, Retirement and Permanent De-List Bids could be reduced or withdrawn within 14 days following ISO-NE's issuance of the qualification determination notifications. *See* Attachment B-1 for further information on these two PSEG amendments.

B. *GEN Group Proposals*

NextEra, GDF SUEZ and Exelon (collectively referred to as the GEN Group) jointly offered the following six motions to amend the IMM's proposal for Markets Committee consideration.

The GEN Group's first motion to amend offered at the Markets Committee was designed to provide resources with an opportunity to remain in the market after submitting a Retirement De-List Bid due to materially changed circumstances. Under this amendment, if the IMM did not approve the discontinuance of the Retirement De-List Bid, the resource would have the right to submit a request to FERC under Section 205 of the Federal Power Act and seek approval to discontinue the Retirement De-List Bid. After a lengthy discussion at the Markets Committee on this issue, and with the understanding among the members that the IMM would try to address concerns raised prior to Participants Committee consideration, this amendment was withdrawn. As described further in the ISO's memorandum included with this Supplemental Notice, the IMM has incorporated language into its proposed Tariff revisions in response to these concerns.

The GEN Group's second amendment would permit Participants to include in their retirement bids expenses associated with products or services that would need to be reallocated to other resources, divisions or Affiliates of the Lead Market Participant. This amendment was unanimously approved by the Markets Committee and the IMM agreed to incorporate these changes into its proposal (as reflected in Tariff revisions included with this memorandum).

The third GEN Group amendment (GEN Group Amendment #3) would require that all Retirement De-List Bids be submitted to the ISO no later than March 1 (nearly one year prior to the relevant FCA). Market Participants with Retirement De-List Bids that are equal to or greater than 0.8 times Net Cost of New Entry (CONE) (defined as the Retirement De-List Bid Threshold) would be required to file their bids with the FERC for approval pursuant to Section 205 of the Federal Power Act. Any FERC decision would be binding. This Amendment also

would eliminate the IMM's proposed proxy de-list bid process. GEN Group Amendment #3 failed with a 42.99% Vote in favor.[3]

GEN Group Amendment #4 would incorporate all aspects of GEN Group Amendment #3, but would eliminate the Retirement De-List Bid Threshold. Under this amendment, all priced retirement bids, not just those that are equal to or greater than a defined threshold level, would need to be filed with the FERC for approval. GEN Group Amendment #4 failed based on a show of hands.

GEN Group Amendment #5 would incorporate the IMM's proposed priced retirement bid process but would allow a Market Participant to submit a Non-Price Retirement Request (NPRR) if it disputes the ISO's retirement determination notification (and would eliminate the conditional and unconditional retirement options of the ISO's proposal). This amendment failed based on a show of hands.

The GEN Group's final amendment, GEN Group Amendment #6, would also allow for an NPRR option. Under this amendment, if a Market Participant elected to retire, but no Retirement De-List Bid was submitted, the Participant would need to submit an NPRR to the ISO by March 1. If the Market Participant chose to submit a Permanent or Retirement De-List Bid, the Participant would have the right to submit an NPRR within five days after ISO issues its retirement determination notification. If an NPRR is submitted, GEN Group Amendment #6 would also require the resource owner to submit that NPRR to the FERC for approval. This amendment also failed based on a show of hands vote.

Further details on all of these GEN Group amendments are provided in Attachment B-2.

C. *NRG's Amendment*

NRG's amendment would allow a resource owner, within seven days of the retirement determination notification, to choose one of the following three options: (1) accept the IMM or FERC determined price and enter into the FCA at the accepted price (if the FCA clearing price is below the accepted price, the resource would retire); (2) fully withdraw its priced Retirement De-List Bid and participate in the FCA as an existing capacity resource; or (3) agree to a conditional retirement bid wherein the FCA is conducted and if the resource owner's submitted retirement bid is below the FCA clearing price, the CSO would be awarded and, conversely, if the retirement bid is above the FCA, the resource retires. Based on a show of hands, the Markets Committee failed to recommend support for the NRG amendment. *See* Attachment B-3.

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

[3] The individual Sector votes consisting of the following: *Generation* – 17.13% in favor, 0% opposed, 3 abstentions; *Transmission* – 1.56% in favor, 15.57% opposed, 0.5 abstention; *Supplier* 17.13% in favor, 0% opposed, 8 abstentions; *Alternative Resources* – 7.19% in favor, 7.19% opposed, 1 abstention; *Publicly Owned Entity* – 0% in favor, 17.13% opposed; and End User - 0% in favor, 17.13% opposed.

(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 neither NEPOOL nor ISO will raise procedural objections before FERC if a Participant advocates for a proposal on this matter that was considered and voted by the Markets Committee on November 18 but not presented for a vote by the Participants Committee.

Agenda Item 9(b): Market Rule 1, Section 12

Any proposed changes to provisions of Section 12 to Market Rule 1 are subject to review and vote(s) by the Reliability Committee. In addition, to garner sufficient support for a Reliability Committee recommendation, changes to Section 12 require a 60% Vote to pass, while other provisions under the jurisdiction of the Reliability Committee require a 66.67% Vote.

The proposed conforming changes to Section 12 relate to the formation of Capacity Zones and the ICR calculation. At its November 20 meeting, the Reliability Committee recommended Participants Committee support for ISO's proposed revisions to Sections III.12.4 and III.12.7.2, with a 64.04% Vote in favor.[4]

Agenda Item 9(c): Section I.3.9.3 and Attachment K of Section II

Because of the higher 66.67% voting threshold required for consideration of changes to Section I.3.9.3, the Reliability Committee took a separate vote at its November 20 meeting on ISO's proposed revisions to Tariff Section I.3.9.3, which relate to the reliability review of proposed retirements. With a 64.04% Vote in favor,[5] the Reliability Committee failed to recommend Participants Committee support for those changes.

Separately, the Transmission Committee also considered corresponding changes to Attachment K of Section II of the Tariff (in provisions regarding assessment of transfer capability and in provisions regarding needs assessments). Similar to Section I.3.9.3, changes to Attachment K also require a 66.67% Vote to pass. Thus, with a 64.04% Vote in favor,[6] the Transmission Committee failed to recommend Participants Committee support for ISO's proposed changes to Attachment K.

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[4] The individual Sector votes consisted of the following: Generation - 0% in favor, 17.13% opposed; Transmission - 15.41% in favor, 1.71% opposed; Supplier 0% in favor, 17.13% opposed, 2 abstentions; Alternative Resources – 14.38% in favor, 0% opposed; Publicly Owned Entity – 17.13% in favor, 0% opposed; and End User - 17.13% in favor, 0% opposed.

[5] The individual Sector votes consisted of the following: Generation - 0% in favor, 17.13% opposed; Transmission - 15.41% in favor, 1.71% opposed; Supplier 0% in favor, 17.13% opposed, 2 abstentions; Alternative Resources – 14.38% in favor, 0% opposed; Publicly Owned Entity – 17.13% in favor, 0% opposed; and End User - 17.13% in favor, 0% opposed.

[6] The individual Sector votes consisted of the following: *Generation* - 0% in favor, 17.13% opposed; *Transmission* - 15.41% in favor, 1.71% opposed; *Supplier* 0% in favor, 17.13% opposed, 1 abstention; *Alternative Resources* – 14.38% in favor, 0% opposed, 1 abstention; *Publicly Owned Entity* – 17.13% in favor, 0% opposed; and End User - 17.13% in favor, 0% opposed.

The following forms of resolution may be used for Participants Committee action, whether voted individually or together:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Section III.13, Appendix A to Market Rule 1 and Section I.2.2 (Definitions) of the Tariff, as proposed by the ISO 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.
>
> RESOLVED, that the Participants Committee supports revisions to the Market Rule 1, Section III.12, as recommended by the Reliability Committee 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 Reliability Committee.
>
> RESOLVED, that the Participants Committee supports revisions to the Section I.3.9.3 and Attachment K of Section II, as proposed by the ISO 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 Chairs and Vice-Chairs of the Reliability and Transmission Committees.

ISO new england

memo

To: NEPOOL Participants Committee

From: Jeff McDonald, Internal Market Monitoring and Mark Karl, Market Development

Date: November 25, 2015

Subject: Further modifications to Section 13 of Market Rule 1 for Retirement Reforms

Pursuant to the November 18, 2015, NEPOOL Markets Committee discussion and internal follow-up, the ISO is making several additional modifications to the retirement reform proposal that was voted on by the NEPOOL Markets Committee at the November 18 meeting, and which is on the agenda for the December 4, 2015, NEPOOL Participants Committee meeting. All the modifications are to Section 13 of Market Rule 1. Brief descriptions and the modifications follow.

In Section III.13.1.2.3.1.5(c), the ISO is removing references to the 20 MW threshold because these short-hand references were not accurate and are fully described in Section III.13.1.2.3.2.1:

Section III.13.1.2.3.1.5(c)

> Permanent De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ and Retirement De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

In Section III.13.1.2.3.2.1, the ISO is making changes to (1) clarify that all Permanent De-List Bids and Retirement De-List Bids submitted by the affiliates of a Lead Market Participant are included in the total of the bids submitted by that participant, (2) clarify that from the second year of submission onward, the Internal Market Monitor will review cost workbooks of all Permanent De-List Bids and Retirement De-List Bids, and (3) remove the descriptor "Internal Market Monitor-approved" from bids the Internal Market Monitor does not review:

Section III.13.1.2.3.2.1.

> If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor ~~because they are less than the Dynamic De-List Bid Threshold and/or~~

~~equal to or less than 20 MW~~ shall ~~have an Internal Market Monitor approved price equal to the submitted price and shall~~ be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

In Section III.13.1.2.3.2.1 and Section III.13.2.5.2.1(b), the ISO is making changes to provide that (1) the participant will submit in each year a Permanent De-List Bid or Retirement De-List Bid Permanent De-List Bid at the price it deems supportable, rather than having the bid automatically carried forward, and (2) a resource can request to discontinue a Permanent De-List Bid or Retirement De-List Bid:

Section III.13.1.2.3.2.1.

If a Permanent De-List Bid or Retirement De-List Bid is submitted ~~has been entered from the prior Forward Capacity Auction~~ pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

Section III.13.2.5.2.1(b)

Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid ~~shall be entered~~ into the qualification process for the following Forward Capacity Auction as described in ~~and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to~~ Section III.13.1.2.3.1.5 ~~and, updated as appropriate, shall be entered into that Forward Capacity Auction~~.

In Section III.13.1.2.3.2.1.1.2, the ISO is making a change to include in the retirement determination notification and the Commission filing the Internal Market Monitor determination on a resource request to discontinue a Permanent De-List Bid or a Retirement De-List Bid:

Section III.13.1.2.3.2.1.1.2.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-approved price based on the Internal Market Monitor review of the net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs as determined by the Internal Market Monitor, and shall include an explanation of the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

In Section III.13.1.2.3.2.1.2.B, the ISO is eliminating the alternative in which Net CONE is substituted for the Lead Market Participant's forecasted expected capacity prices:

Section III.13.1.2.3.2.1.2.B

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with ~~Net CONE (or, if Net CONE is not yet published for the Capacity Commitment Period in question,~~ the Internal Market Monitor's estimate thereof~~)~~ in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

In Section III.13.1.2.4.1, the ISO is removing the descriptor "IMM-approved" in order to conform with the change to Section 13.1.2.3.2.1 that removes the descriptor "Internal Market Monitor-approved" from bids the IMM does not cost review:

Section III.13.1.2.4.1.

If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the ~~IMM-approved Permanent De List Bids and IMM-approved Retirement De List Bids~~ prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

Administrative Export De-List Bid is a bid 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 Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology 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.

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

Asset-Specific Going Forward Costs are the net ~~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.13.1.2.3.2.1.1.1~~2.~~ (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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.13.7.2.7.1.1.2(a) of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of

the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

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

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 each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); 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, 2018, 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.

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

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

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 July 14, 2014.

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

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

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

Capacity 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 July 14, 2014.

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 Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.

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 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.

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.

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

Common Costs are those costs associated with a Station that are avoided only by ~~(1)~~ the clearing of the Static De-List Bids, ~~or~~ the Permanent De-List Bids, or the Retirement 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 Resource is defined in Section III.13.1.1.2.3(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 estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

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, 2018, 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, 2018.

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

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

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

Day-Ahead 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, 2018, 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 an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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, 2018.

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 Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and 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 below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a 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, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

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

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

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

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.

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

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

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

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

Energy Non-Zero Spot Market Settlement Hours are 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.

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~~ for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

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

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

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

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

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

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

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

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

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

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

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

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) cold Notification Time plus cold Start-Up Time 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.

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

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

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

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

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

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

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

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

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

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

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 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.

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

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

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

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

Import Capacity Resource 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, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 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 Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

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

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

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

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

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

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

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

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

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

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 Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is 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 or a Public Policy Transmission 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, 2018, 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, 2018, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 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 Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

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. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

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 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 Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

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 calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited

to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

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 Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying

the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (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.

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.13.1.1.2.1 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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

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 is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity

Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

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

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been

dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

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.13.7.2.7.1 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.13.1.2.3.1.5~~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.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(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 Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity

Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource 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.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

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.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

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

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

Real-Time Congestion Revenue is defined in Section III.3.2.1(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, 2018, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2018.

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

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 Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(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 Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 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 Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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 Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation 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.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily

terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

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 Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

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).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

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

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System 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, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

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 (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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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 (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate 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 (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

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.

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 Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 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.

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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 Regulation Market.

III.14.1 Regulation Market System Requirements.

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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.

III.13.1. Forward Capacity Auction Qualification.

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 (Section 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 III.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 Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, 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 FCM Deposit.

III.13.1.1. New Generating Capacity Resources.

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.

III.13.1.1.1. Definition of New Generating Capacity Resource.

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.13.1.1.1.1. 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 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.13.1.1.1.3 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.13.1.1.1.4. 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.13.1.1.1.5. 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.13.1.1.1.3 or Section III.13.1.1.1.4, 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.13.1.1.1.6. 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.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement 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).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable

energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the state in which it is geographically located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export De-List Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

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, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, an Interconnection Request under Schedules 22, 23 or 25 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 interconnection procedures described in Schedules 22, 23 and 25 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 FCM 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. 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, 23 and 25 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form 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.13.1.1.2.8.

(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, 23 and 25 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 interconnection procedures described in Schedules 22, 23 and 25 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, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. 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 pursuant to Section III.13.1.1.2.2.1.

(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.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. 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.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(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 of Section II of the Transmission, Markets and Services Tariff.

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 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.13.1.1.2.2:

(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.13.1.1.2.3. 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 Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 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 or Capacity Network Import Interconnection Service in a manner that meets the Capacity

Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 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) or Elective Transmission Upgrade Interconnection Customer 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) or Elective Transmission Upgrade Interconnection Customer, 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, 23 and 25 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 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, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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.13.1.1.2.3(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 Resource; (ii) for the notification to a Conditional Qualified New 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 Resource, the Queue Position of the Conditional Qualified New 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.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Resource shall submit a Renewable Technology Resource election form no later than five Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.2.5.3. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.2.2.5 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

(a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c) and (d) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than three Business Days after the deadline for submitting Renewable Technology Resource elections.

(b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.

(c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on or after June 1, 2020 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Generating Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

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.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

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.13.1.2.2.2.1(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~~ Retirement 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 two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity ~~Qualification~~ Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to 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) [Reserved.]

(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 the close of the New Capacity Show of Interest Submission Window~~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 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) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than ~~15~~ 20 Business Days before the Existing Capacity ~~Qualification~~Retirement 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 10~~5~~ Business Days before the Existing Capacity ~~Qualification~~Retirement 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, or a Retirement 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 Retirement Package and 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 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and~~,~~ 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~~. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement ~~Qualification~~ Deadline, except as provided for in Section III.13.1.2.4.1. 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, except as provided for in Section~~s~~ III.13.1.2.3.1.1~~ and III.13.1.2.3.1.5.2~~. 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, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. 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; neither a Permanent De-List Bid nor a Retirement De-List Bid may ~~not~~ be combined with any other type of de-list or export bid.

Static De-List Bids and~~,~~ 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 for a Forward Capacity Auction is $5.50/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.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, 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 qualification process. 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). 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 Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. ~~Permanent De-List Bids.~~ **[Reserved.]**

~~A Lead Market Participant with an Existing 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 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 at or 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 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 at or 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Permanent De-List Bids and ~~Non-Price~~ Retirement ~~Request~~De-List Bids.

~~III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.~~

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ and Retirement De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

~~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 submitted in accordance with the timing requirements of Section III.13.1.2.3.1.5.2 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 Permanent De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.1, a Non-Price Retirement Request may be submitted for the affected portion of the bid within 14 days after the issuance by the ISO of the qualification determination notification or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.~~

III.13.1.2.3.1.5.1~~3~~. Reliability Review of ~~Non-Price~~ Permanent De-List Bids and Retirement ~~Requests~~ De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-approved Permanent De-List Bids and Internal Market Monitor-approved Reitrement De-List Bids that are above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) . The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee no later than 30 days after the ISO submits to the Commission the retirement filing described in Section III.13.8.1(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than 10 Business Days after being informed that a resource is needed for relaiblity reasons pursuant to this Section III.13.1.2.3.1.5.1, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

~~(i)~~ For a Permanent De-List Bid above the Forward Capacity Auction Starting Price, the portion of the resource subject to the de-list bid -will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(ii)

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will be continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

~~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 and Retirement 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, or Retirement 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, or Retirement 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 of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, ~~and~~ Permanent De-List Bid and Retirement De-List Bids 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 establish an Internal Market Monitor-determined or Internal Market Monitor–approved price for 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 Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and~~,~~ Export Bids~~ at or Above the Dynamic De-List Bid Threshold~~, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid~~,~~ and each Export Bid at or above the Dynamic De-List Bid Threshold~~, and each Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (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).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor ~~because they are less than the Dynamic De-List Bid Threshold and/or equal to or less than 20 MW~~ shall ~~have an Internal Market Monitor-approved price equal to the submitted price and shall~~ be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each ~~of these~~ bid component~~s~~ must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make ~~such~~ the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted ~~has been entered from the prior Forward Capacity Auction~~ pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-

List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including ~~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, cash flows, opportunity costs, 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~~ Static De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a ~~Permanent~~ Static De-List Bid or an Export Bid is not consistent with the sum of the resource's net going forward costs~~,~~ plus reasonable expectations about the resource's Capacity Performance Payments~~,~~ plus reasonable risk premium assumptions~~, and~~ plus reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing. If an Internal Market Monitor-determined price is established for a ~~Permanent~~ Static De-List Bid or an Export Bid, 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~~c) shall include an explanation of the Internal Market

Monitor-determined price 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.

~~**III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.**~~

~~If the Internal Market Monitor determines, after due consideration and consultation with a Lead Market Participant, that a Static De-List Bid is not consistent with a 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 Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing.~~

~~If an Internal Market Monitor-determined price is established for a bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-determined price 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.~~

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.
After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop an Internal Market Monitor-approved Permanent De-List Bid or Internal Market-Monitor-approved Retirement De-List Bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-approved price based on the Internal Market Monitor review of the net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance

Payments, and reasonable opportunity costs as determined by the Internal Market Monitor, and shall include an explanation of the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor~~using ISO spreadsheets and forms provided~~, and may supplement this information with other evidence~~ as deemed necessary~~. A Static De-List Bid or~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ shall be considered consistent with the Existing 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 Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \text{ x } InfIndex}{(CQ_{Summer,}\, kw) \text{ x } (12, months)}$$

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_{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.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values.

The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with ~~Net CONE (or, if Net CONE is not yet published for the Capacity Commitment Period in question,~~ the Internal Market Monitor's estimate thereof~~)~~ in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life,

the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid ~~at or above the Dynamic De-List Bid Threshold~~, ~~or~~ Permanent De-List Bid, or Retirement De-List Bid at or 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 Capacity Resource that submits a Static De-List Bid, or an~~,~~ Export Bid ~~at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid~~at or 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.A 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 Capacity Resource submitting a Static De-List Bid or an~~,~~ Export Bid, ~~at or above the Dynamic De-List Bid Threshold, or~~ Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the 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. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all ~~de-list bids~~Static 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.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery

1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, 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:

$$\frac{\textit{Cost Of Capital}}{(1-(1+\textit{CostOfCapital})^{-\textit{RemainingLife}})}$$

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. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.

(a) No later than 90 days after the Existing Capacity Retirement Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement De-List Bid concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(b) 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~~ and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review ~~subject~~ pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than ten Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the ~~IMM-approved Permanent De-List Bids and IMM-approved Retirement De-List Bids~~ prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

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 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 established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for

participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

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~~ Retirement 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.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

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) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

(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~~ 15 Business Days prior to the Existing Capacity ~~Qualification~~ Retirement 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.

Contract Description	**MW**	**Contract End Date**
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	

VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing 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.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service. Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

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 Project Sponsor 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 the contract period including the entire Capacity Commitment Period, 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 Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor 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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor 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.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, 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 apply in addition to the requirement that the Project Sponsor 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 Project Sponsor, 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 and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 Project Sponsor 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.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, 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 apply in addition to the requirement that the Project Sponsor 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 for the length of the multi-year contract.

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 Project Sponsor 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 Project Sponsor 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 Project Sponsor 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 only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other 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.

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 unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each 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.13.1.3.5.6. Review by Internal Market Monitor of Offers from New 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 New Import Capacity Resources. An offer from 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.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted 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.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

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 a Commercial Operation Date before June 1, 2018, or a Demand Response Capacity Resource that cleared in the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period, shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2018. 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 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 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that neither a Permanent De-List Bid ~~Non-Price~~ nor a Retirement ~~Requests~~ De-List Bid 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 Section~~s~~ 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 or Retirement De-List Bids pursuant to Section III.13.1.2.3.1.5~~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~~ Retirement 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.13.1.4.2.2.4.2. 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 six 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~~ 20 Business Days before the Existing Capacity ~~Qualification~~ Retirement 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, Retirement 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. 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, 2018, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, 2018, 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 using the Real-Time Emergency Generation Asset's 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 using the Real-Time Emergency Generations Asset's Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2018, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2018, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

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.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

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.

III.13.1.4.6.1. Establishment of 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.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

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 , 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.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.
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, 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.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

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.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

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.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

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.13.1.2.2.5.2 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.

(h) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five 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 FCM 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 Capacity Load Obligation 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.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

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, a Retirement 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, retire 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 and Retirement 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) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids. ~~If a Permanent De-List Bid at or above the Dynamic De-List Bid Threshold or a Static De-List Bid for which an Internal Market Monitor-determined price has not been established, 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~~Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such 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(b), 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, and Retirement 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.

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 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 FCM Deposit 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 Forward Capacity Auction Starting Price. If the FCM 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, financial assurance required prior to the auction pursuant to FAP 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 financial assurance required prior to the auction pursuant to FAP will be released 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 as described in the ISO New England Financial Assurance Policy 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 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.

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 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 Section III.13 shall be used to reduce charges 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 or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection

Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff 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 or the Elective Transmission Upgrade 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, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			

$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

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.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

~~The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.~~

~~New Capacity Show of Interest Submission Window~~	~~Existing Capacity Qualification Deadline~~	~~New Capacity Qualification Deadline~~	~~First Day of Forward Capacity Auction for the Capacity Commitment Period~~	~~Capacity Commitment Period Begins~~
~~For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources,~~	~~Apr. 30, 2007~~	~~June 15, 2007~~	~~Feb. 4, 2008~~	~~June 1, 2010~~

~~Dec. 18, 2006 through Feb. 28, 2007~~				
~~Sept. 18, 2007 through Nov. 14, 2007~~	~~Mar. 14, 2008~~	~~Apr. 29, 2008~~	~~Dec. 8, 2008~~	~~June 1, 2011~~
~~July 15, 2008 through Sep. 16, 2008~~	~~Feb. 3, 2009~~	~~Feb. 17, 2009~~	~~Oct. 5, 2009~~	~~June 1, 2012~~
~~May 15, 2009 through July 14, 2009~~	~~Dec. 1, 2009~~	~~Dec. 15, 2009~~	~~Aug. 2, 2010~~	~~June 1, 2013~~
~~Mar. 15, 2010 through May 14, 2010~~	~~Oct. 1, 2010~~	~~Oct. 15, 2010~~	~~June 6, 2011~~	~~June 1, 2014~~
~~Mar. 1, 2011 through Mar. 14, 2011~~	~~Aug. 1, 2011~~	~~Aug. 15, 2011~~	~~Apr. 2, 2012~~	~~June 1, 2015~~
~~Jan. 3, 2012 through Jan. 17, 2012~~	~~June 1, 2012~~	~~June 15, 2012~~	~~Feb. 4, 2013~~	~~June 1, 2016~~
~~Feb. 14, 2013 through Feb. 28, 2013~~	~~June 3, 2013~~	~~June 17, 2013~~	~~Feb. 3, 2014~~	~~June 1, 2017~~

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 Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment~~tn~~ Period;

(c) the New Capacity Show of Interest Submission Window will be in ~~February~~ April~~(after the Forward Capacity Auction for the prior Capacity Commitment Period)~~, approximately four years and ~~three~~ two months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June, ~~just over~~approximately 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.

Existing Capacity Retirement Deadline	**New Capacity Show of Interest Submission Window**	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
March (X-4)	~~Feb.~~April (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 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 (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), 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.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

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.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve pursuant to Section III.13.2.3.3.

The System-Wide Capacity Demand Curve is defined as follows:

(a) For quantities less than the Installed Capacity Requirement (net of HQICCs) at 0.200 LOLE, the price is max [1.6 multiplied by Net CONE, CONE];

(b) For quantities equal to or greater than the Installed Capacity Requirement (net of HQICCs) at 0.200 LOLE, but less than 0.011 LOLE, the price will be determined by a straight line between the price at 0.200 LOLE (which shall be max [1.6 multiplied by Net CONE, CONE] and the price at 0.011 LOLE (which shall be zero);

(c) For quantities equal to or greater than the Installed Capacity Requirement (net of HQICCs) at 0.011 LOLE, the price is zero.

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:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.
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 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, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource 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 applicable 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. 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, 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, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, 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 Capacity 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \ldots & \ldots \quad , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

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) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity 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.

(v) Capacity associated with a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer 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 an offer 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 not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources ~~Submitted in Qualification~~.**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized ~~submitted~~ in the qualification process ~~(~~or as otherwise directed by the Commission~~)~~, shall be automatically bid into the appropriate round~~(s)~~ of the Forward Capacity Auction, such that each such resource's FCA 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, Retirement 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. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). 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).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List

Bid, and shall be entered into the appropriate rounds of the Forwad Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an ~~Permanent De-List Bid or~~ Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any ~~Static De-List Bid or Permanent De-List Bid converted into a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 and any~~ Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification

Package, 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 Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New 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 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 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 Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New 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 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 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 (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, 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 amount of capacity determined by the System-Wide Capacity Demand Curve;

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 amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price) 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 amount of capacity determined by the System-Wide Capacity Demand Curve, 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 amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the amount of capacity determined by the System-Wide Capacity Demand Curve 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 amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price) 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 amount of capacity determined by the System-Wide Capacity Demand Curve;

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 amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price) and the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (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 cleared amount of capacity determined by the System-Wide Capacity Demand Curve. 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~~A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, ~~or~~ Permanent De-list Bid, or Retirement De-List Bid shall ~~be~~ clear 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 and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. 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.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $14.04/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $11.08/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e), except that the energy and ancillary services offset will be adjusted

using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

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 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 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 and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid, Retirement De-List Bid or Proxy 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.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid ~~shall be entered~~ into the qualification process for the following Forward Capacity Auction as described in ~~and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to~~ Section III.13.1.2.3.1.5 ~~and, updated as appropriate, shall be entered into that Forward Capacity Auction~~.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the intial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) 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) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price, as adjusted pursuant to Sections III.13.2.7.9 and III.13.2.8, during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid 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) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

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 Review~~Reasons~~.

The ISO shall review each ~~Non-Price~~ Retirement ~~Request~~De-List Bid, 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; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. 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 criteria, or ISO New England System Rules. ~~Non-Price Retirement Requests and~~ D~~d~~e-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected 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 the Local Sourcing Requirement for a Capacity Zone.

(b) Where a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~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~~c) 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~~d) A resource that has a de-list bid rejected ~~pursuant to this Section III.13.2.5.2.5~~for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and~~. 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 a Capacity Supply Obligation~~s~~ as described in Section III.13.6.1.

(e~~e~~) 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~~caused the ISO to reject the de-list bid 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~~f) If the reliability need that ~~prevented the de-listing of the resource~~caused the ISO to reject the de-list bid 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).~~ retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the

subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(~~e~~g) If a Permanent De-List Bid or a Retirement De-List Bid~~that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request~~ is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, 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~~h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list 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~~ De-List Bid or Permanent De-List Bid 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~~De-List Bid~~, 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, t~~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, or partial Retirement De-List Bid ~~would otherwise clear in the Forward Capacity Auction but the de-list bid~~ has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or 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. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

~~(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 or a Retirement 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 or III.13.1.2.3.1.5.1 or 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 Commission-approved Permanent D~~d~~e-L~~l~~ist B~~b~~id or Commission-approved Retirement 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 or Retirement 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 Commission-approved Permanent De-List Bid or Commission-approved Retirement 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 or Retirement De-List Bid was submitted. 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 or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b) . Resources that elect payment based on the ~~accepted~~ Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement 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 or Retirement 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.~~

(c~~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~~d) **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, or Retirement 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Resources.~~:~~

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section ~~III.13.2.5.2.5.3(a)(iii)~~III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section 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(b~~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 and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: ~~that~~ submitted ~~s~~ a ~~Non-Price~~ Retirement De-List Bid ~~Request~~ that was not included in the Forward Capacity Auction pursuant to Section ~~III.13.1.2.3.1.5~~ III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid cleare~~d~~ in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1~~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)~~. In~~f~~ the case of a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Bid rejected for reliability, ~~is approved after the resource has a Capacity Supply Obligation for the Cappacity Commitment Period for which the Non-Price Retirement Request was submitted~~ if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless 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 ~~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) A~~n~~ resource, or portion thereof, ~~Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request~~ that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~has been approved~~was submitted 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 no later than 15 days prior to commencement of the relevant Forward Capacity Auction. 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, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: ~~that has~~ submitted a ~~non-partial~~ Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III. III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid ~~has~~ clear~~ed~~ 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.~~ The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid,

consistent with the provisions of Schedules 22 and 23 of the OATT. A resource ~~whose resource~~that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) 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-.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) ~~with a cleared non-partial Permanent De-List Bid~~ may ~~retire~~ be permanently de-listed ~~the resource~~ earlier than the Capacity Commitment Period for which its Permanent De-List Bid ~~has cleared~~was submitted 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 Retirement De-List Bid, 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 Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, 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 will not be rationed 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 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) [Reserved.]

(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 Resource's location or the offer associated with the Conditional Qualified New 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 and Retirement 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 and Retirement 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 applicable Net CONE value; 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 applicable Net CONE value.

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 import-constrained 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)~~,~~ plus the capacity of Proxy De-List Bids entered as as result of a retirement election pursuant to Section III.13.1.2.4.1(a)) minus capacity otherwise obligated in the 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 the max [applicable Net CONE value, Capacity Clearing Price for the Rest-of-Pool Capacity Zone] 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) [Reserved.]

(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. [Reserved.]

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition in an import-constrained Capacity Zone if there is not Inadequate Supply and 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), plus the capacity of Proxy De-List Bids entered as as result of a retirement election pursuant to Section III.13.1.2.4.1(a), minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Local Sourcing Requirement; 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. 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 Local Sourcing Requirement.

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) max [applicable Net CONE value, the

Capacity Clearing Price for the Rest-of-Pool Capacity Zone] during the associated Capacity Commitment Period. Notwithstanding the foregoing, 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) that cleared in the seventh Forward Capacity Auction in the NEMA Capacity Zone shall be paid $6.661/kW-month 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) that cleared in the eighth Forward Capacity Auction in all Capacity Zones but the NEMA Capacity Zone shall be paid $7.025/kW-month. 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 the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under this Section III.13.2.8.2.

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 Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New 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.13.1.1.1.2, 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.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) 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.

Except as described in Section III.13.3.7, if as a result of milestone date revisions, the Commercial Operation milestone date is after the start of any Capacity Commitment Period in which the resource has a Capacity Supply Obligation (except 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 (or, for any demand bid submitted by the ISO in the third annual reconfiguration auction associated with the seventh Capacity Commitment Period, at $12.11/kW-month), 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.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the

Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the resource's ability to achieve Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Section III.13.6 and Section III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves commercial operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and 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) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5). Neither the Project Sponsor, nor the ISO on the Project Sponsor's behalf, will take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4, but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be

adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

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 the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) 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~~ De-List Bid 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~~ Retirement 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.13.1.1.1.2 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.13.4.2.1.2.1.1.2. 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~~ Retirement 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.13.4.2.1.2.1.1.2(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 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.13.1.1.1.2 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.13.1.1.1.2 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.13.1.1.1.2 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.13.1.1.1.2 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.13.4.2.1.2.2.2.3. 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.13.4.2.1.2.2.3. 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.13.4.2.1.2.2.4. Demand Resources.

III.13.4.2.1.2.2.4.1. 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: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DR Audit value in effect after the most recently completed summer season or its Demand Resource Commercial Operation Audit performed during the most recently completed summer season, whichever is more recent.

(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.13.4.2.1.2.2.4.2. 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: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DR Audit value in effect after the most recently completed winter season or its Demand Resource Commercial Operation Audit performed during the most recently completed winter season, whichever is more recent.

(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 (or, in the case of a resource that cleared in the seventh Forward Capacity Auction, at $12.11/kW-month) 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 reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC 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.

(b) 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.

(c) 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 reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). 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.

III.13.4.3. 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), Local Sourcing Requirements and Maximum Capacity Limits 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 external interface limits, as follows:

(a) For each Capacity Commitment Period that begins on or before June 1, 2017, 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 external interface 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.

(b) For each Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall submit demand bids for the amount of additional capacity needed to meet the Local Sourcing Requirements and shall submit supply offers in the third annual reconfiguration auction for a Capacity Commitment Period to release capacity exceeding the Maximum Capacity Limits or external interface limits.

(c) No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall provide notice regarding whether the ISO will be submitting supply offers or demand bids in that auction.

(d) Any demand bid submitted by the ISO in an annual reconfiguration auction shall be at the Forward Capacity Auction Starting Price, except for any demand bids submitted by the ISO in annual reconfiguration auctions associated with the seventh Capacity Commitment Period, which shall be at $12.11/kW-month.

(e) 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.

(f) 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.

(g) 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.

(h) 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.13.6.1.1.1.

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. For each annual reconfiguration auction, the New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period.

For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve 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.

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.

First Annual Reconfiguration Auction	Second Annual Reconfiguration	Third Annual Reconfiguration	Capacity Commitment Period Begins
N/A	May 2009	March 2010	June 1, 2010
N/A	May 2010	March 2011	June 1, 2011
N/A	May 2011	March 2012	June 1, 2012
N/A	May 2012	March 2013	June 1, 2013
N/A	August 2013	March 2014	June 1, 2014
June 2013	August 2014	March 2015	June 1, 2015
June 2014	August 2015	March 2016	June 1, 2016
June 2015	August 2016	March 2017	June 1, 2017

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. For each monthly reconfiguration auction, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.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 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) [Reserved.]

(g) Prior to April 1, 2015, 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 review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the 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 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.

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.

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.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource 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 Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating 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 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 Bilateral, a Supplemental Availability 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 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 Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) 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 Bilateral, and shall reject the Supplemental Availability 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 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 (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, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability 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 Bilateral is to modify the 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-Up 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.

III.13.6.1.2.1. Energy Market Offer Requirements.

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 or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) 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.

(e) 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 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 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.

III.13.6.1.3.1. Energy Market Offer Requirements.
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.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

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.

Commencing June 1, 2018, a Market Participant with a Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market. The sum of the Demand Reduction Offers must be equal to or greater than the Demand Response Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Demand Response Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand

Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet 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.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a resource Demand Response Resources associated with a Demand Response Capacity Resource 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) 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 any Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource except as provided in Section III.13.6.1.5.4.3.3.

(c) 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.

(d) 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 that is mapped to a Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.

(b) 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 III.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.

(c) 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, 2018, the audit results for Demand Response Resources comprised of Demand Response 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, 2018 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.

(d) If one or more Demand Response Assets of a Demand Response Resource 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 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 was available for dispatch by the ISO in that prior month, and if the Demand Response Asset was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response 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 is not subject to Section III.13.6.1.5.4.1(b) and has received a Dispatch Instruction in a season for 100% of its highest Capacity Supply Obligation for the current DR Auditing Period lasting at least one hour, not including the 30 minute Demand Response Resource Notification Time, may elect to use the first 60 minute period of the event after the 30 minute Demand Response Resource Notification Time to satisfy the Seasonal DR Audit requirements.

A Real-Time Demand Response Resource that is subject to Section III.13.6.1.5.4.1(b) and has received a Dispatch Instruction in a season for 100% of its highest Capacity Supply Obligation for the current DR Auditing Period lasting at least one hour, not including the 30 minute notification time, may elect to use the first 60 minute period of the event after the 30 minute notification time to satisfy the Seasonal DR Audit requirements, provided that any Real-Time Demand Response Assets mapped to the Real-Time Demand Response Resource that are located behind the same end-use customer meter as Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource must be audited concurrently with the Real-Time Emergency Generation Resource audit in the same DR Auditing Period. The performance of Real-Time Demand Response Assets that are audited concurrently with a Real-Time Emergency Generation Resource audit in a DR Auditing Period shall be used in establishing the Real-Time Demand Response Resource's Seasonal DR Audit value for that DR Auditing Period.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource's audit value under these provisions 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 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; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.8B.6 is assessed a zero audit value.

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 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 over the audit duration by proportionally reducing each associated Demand Response 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 Demand Response Resource's Audited Demand Reduction.

If an event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the event at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market

Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

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) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit 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 prior to the end of the first month in which the Demand Resource has a Capacity Supply Obligation 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 Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) 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. 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 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. 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 Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction. Audit results for the Demand Response Resources will be based on the sum of the average demand reductions demonstrated during the audit by each Demand Response 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 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 Maximum Reduction 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;

(b) In calculating the commercial capacity value of the Demand Resource for purposes of determining release of financial assurance pursuant to Section III.13.1.9.2.2, until the next Demand Resource Commercial Operation Audit is conducted;

(c) For determination regarding termination under Section III.13.3.4(c); and

(d) 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.

When a New Demand Response Asset Audit is performed, the commercial capacity value and Seasonal DR Audit value of the Demand Resource to which the asset is mapped shall be updated to reflect any changes in the composition of the Demand Resource.

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 or until a Demand Resource Commercial Operation Audit is performed. 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. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

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.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

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.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

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.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. 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 E1. A Market Participant with a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market for 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.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with 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 into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with 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 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.

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. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

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.

(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, 2018, 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.

(c) Prior to June 1, 2018, 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.

(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 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.13.7.1.1.1.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 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 Resouce 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 Resouce 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.

III.13.7.1.5.8.3.1. 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.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

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.13.7.1.6. 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) (or in the case of Inadequate Supply or Insufficient Competition, the payment rate applicable to that resource under Section III.13.2.8) 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 six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

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).

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

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, 2018, 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, 2018. 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 From Real-Time Emergency Generation Assets.

For Capacity Commitment Periods commencing on or after June 1, 2018, 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 demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset. The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

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.

For Capacity Commitment Periods beginning prior to June 1, 2019, 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:

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.

(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 (1) the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period and (2) the Capacity Clearing Price as adjusted in Section III.13.2.7.3(b) (or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing

Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8) 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 in the case of Inadequate Supply or Insufficient Competition, on the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under 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:

Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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 Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to 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) 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 (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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 (1) difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply or Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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 (1) the difference between the quantity requested and the quantity delivered and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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 (1) the Import Capacity Resource's Capacity Supply Obligation and (2) the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), or in the case of Inadequate Supply of Insufficient Competition, the lower of (a) the Capacity Clearing Price and (b) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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.

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)) , or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply or Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 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)) , or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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, (as adjusted pursuant to Section III.13.2.7.3(b)), or in the case of Inadequate Supply of Insufficient Competition, multiplied by the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8, 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.

III.13.7.3.1. 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; load that is modeled as an Asset Related Demand or discrete load asset and is exclusively related to an Alternative Technology Regulation Resource following AGC dispatch instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A 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 Zone 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.

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)), or in the case of Inadequate Supply or Insufficient Competition, the lower of (1) the Capacity Clearing Price, and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 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)), or in the case of Inadequate Supply or Insufficient Competition, minus the lower of (1) the Capacity Clearing Price and (2) the payment rate for Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources under Section III.13.2.8 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.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. 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.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63
Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12

Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

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.

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 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved 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).

(c~~b~~) 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~~ Static De-List Bids, Export Bids, and Administrative De-Lits Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids ~~de-list bids~~ 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 the Internal Market Monitor establishing an Internal Market Monitor-determined price for 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~~d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(~~a~~c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 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 of the filing that directs otherwise, the determinations contained in the informational filing 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).

~~(c) For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the ISO shall make an informational filing with the Commission no later than December 16, 2014 detailing its determination of the New Resource Offer Floor Price for each New Import Capacity Resource making a request and cost information submittal as described in Section III.13.1.3.5.6 and providing supporting documentation for each such determination. These determinations shall be filed confidentially with the Commission in the informational filing. Any comments or challenges to the determinations contained in the informational filing described in this Section III.13.8.1(c) must be filed with the Commission no later than December 23, 2014. If the Commission does not issue an order by January 15, 2015 that directs otherwise, the determinations contained in the informational filing shall be used in conducting the ninth 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 by January 15, 2015, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted 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 Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 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 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.]**

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1 Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III. A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer 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 l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential 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, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. 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 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. 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.

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 Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five B~~b~~usiness D~~d~~ays:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five B~~b~~usiness D~~d~~ays of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

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. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, 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 B~~b~~usiness D~~d~~ays following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, 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 must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of	Months Precluded (starting

Incidents	from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
(b) refusing to make a Supply Offer, or 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 B~~b~~usiness D~~d~~ays prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(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.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall

be based on the mitigated value. The second LMP shall be calculated 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 in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to 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 in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to 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. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to 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.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. 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 B~~b~~usiness D~~d~~ays 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.5.10. 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-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.
(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.
(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

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) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
    (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
    (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
    (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.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
(b) Costs must be documented.
(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
(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:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits; and,
(c) other operating permits that limit production of energy.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

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 Shortage Event, as described below. The

evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

(a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.

(b) Competitiveness Evaluation of Energy Offer At Low Load.

  (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

  (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

(c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is 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.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, 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.

(d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:

  i. The Start-Up Fee (cold start);
  ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and
  iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor 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: $(LMP_{real\ time} / LMP_{day\ ahead}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{real\ time} / LMP_{day\ ahead}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

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.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

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.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

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. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.
If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, 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, and (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.

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 exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating

the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (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.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully

challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A*.**

III.A.17.2.3. Reporting on General Performance of the 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 B~~b~~usiness D~~d~~ays to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct 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.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21 Review of Offers From New Resources in the Forward Capacity Market.

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 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.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1 Offer Review Trigger Prices for the Ninth Forward Capacity Auction.

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

Generation Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$13.424
combined cycle gas turbine	$8.866
on-shore wind	$10.320

Demand Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**

Load Management	$7.094
previously installed Distributed Generation	$1.145
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the new Demand Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

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; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/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 recalculate the Offer Review Trigger Price pursuant to subsection (a) above 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. 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 Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above 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.

(d) For new Demand Resources other than Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above 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 comprised of 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 Demand Resources comprised of Energy Efficiency) 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.

(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:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "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	BLS "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"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(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:

Cost Component	**Index**
labor, administrative and general	BLS "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 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)”

(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 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the 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 12 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 and Offer Prices.

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

(a) For a Lead Market Participant with 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, III.13.1.3.5 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.
>
> For a New Generating Capacity Resource, 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, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with 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, III.13.1.3.5 and III.13.1.4.2.4, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

> For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, 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 and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(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 Demand 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 Demand Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Demand Resource, and expected costs avoided by the end-use 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 Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. 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 prices are 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, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices 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(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3 Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

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.

III.A.22 [Reserved.]

III.A.23 Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1 Pivotal Supplier Test

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2 Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3 ~~Timing of~~ Pivotal Supplier Test ~~and~~ Notification of Results.

~~The pivotal supplier test will be calculated prior to the commencement of the Forward Capacity Auction, and no earlier than the deadline by which a supplier that has submitted a Non-Price Retirement Request for capacity must elect to retire for that auction.~~

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4 Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-

List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to~~fails~~ the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor–estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

~~i.~~ The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor–estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v.

vi. The Internal Market Monitor–estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates

under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

III.12.4 Capacity Zones.

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

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

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

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

III.12.7.2 Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and capacity requirement values for the System-Wide Capacity Demand Curve shall include:

(a) all Existing Generating Capacity Resources,

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

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

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

but shall exclude:

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

(f) capacity de-listed or retired as a result of Permanent De-List Bids or Retirement De-List Bids ~~resources for which Permanent De-list Bids cleared~~ in previous Forward Capacity Auctions, and ~~or for which Non-Price Retirement Requests have been received.~~

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

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and capacity requirement values for the System-Wide Capacity Demand Curve shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand

Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

I.3.9.3 Reliability Review of Retirements of or Reductions in Capacity of an Existing Demand Resource or Existing Generating Capacity Resource:

Proposals for the reduction of capacity from an Existing Demand Resource or an Existing Generating Capacity Resource below its Qualified Capacity amount for the relevant Capacity Commitment Period, including unit retirement, are reviewed for reliability impact pursuant to the terms set out in Section III.13.2.5.2.5 of the Tariff. Once a demand resource or generating resource has a cleared de-list bid pursuant to Section III of the Tariff it may reduce its capacity consistent with the terms of its de-list bid for all or any part of the Capacity Commitment Period of the approved de-list without further reliability review. However, any proposed physical modification to a de-listed generating facility must comply with the requirements, including the reliability review process, set out in Schedules 22 or 23, as applicable. ~~Once a generating resource has an approved Non-Price Retirement Request, it must retire as described in Section III.13.2.5.2.5.3(a), except as provided in Section III.13.2.5.2.5.2, without further reliability review.~~

ATTACHMENT K

REGIONAL SYSTEM PLANNING PROCESS

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3.1 Description of RSP

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental, and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

(i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;

(ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

(iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and

(iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment and the competitive solution process

described in Section 4.3 of this Attachment, may meet the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades (which, for the foregoing types of upgrades, may include the portions of Interregional Transmission Projects located within the New England Control Area) and of External Transmission Projects, and Public Policy Transmission Upgrades. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

The RSP shall also include the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market pursuant to ISO Tariff Section III.12. Each annual assessment of interface boundaries that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market will model out-of-service all submitted ~~Non-Price~~ Retirement ~~Requests~~ De-List Bids and submitted Permanent De-List Bids as well as rejected~~-~~ for~~-~~ reliability Static De-List Bids and rejected~~-~~ for~~-~~ reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

Each RSP shall be built upon the previous year's RSP.

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Non-Applicability of Sections 4.1 through 4.3; Needs Assessments

The reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need. The market efficiency planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a market efficiency need. The public policy planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. For needs identified initially as reliability, market efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred solution may also satisfy identified reliability needs of the system as described in Sections 4A.5(e) or 4A.7, respectively, of this Attachment K. Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities while promoting the operation of efficient wholesale electric markets in New England. A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) support the efficient operation of the wholesale electric markets; (iv) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (v) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, if:

(i) a need for additional transfer capability is identified by the ISO in its ongoing evaluation of the PTF's adequacy and performance;

(ii) a need for additional transfer capability is identified as a result of an ERO and/or NPCC reliability assessment or more stringent publicly available local reliability criteria, if any;

(iii) constraints or available transfer capability limitations that are identified possibly as a result of generation additions or retirements, evaluation of load forecasts or proposals for the addition of transmission facilities in the New England Control Area;

(iv) as requested by a stakeholder pursuant to the provisions of Section 4.1(b) of this Attachment; or

(v) as otherwise deemed appropriate by the ISO as warranting such an assessment.

(b) Requests by Stakeholders for Needs Assessments for Economic Considerations

The ISO's stakeholders may request the ISO to initiate a Needs Assessment to examine situations where potential regulated transmission solutions or market responses or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of this OATT, (ii) reduced congestion, or (iii) the integration of new resources and/or loads on an aggregate or regional basis (an "Economic Study").

Requests for Economic Studies shall be submitted, considered and prioritized as follows:

(i) By no later than April 1 of each year, any stakeholder may submit to the ISO for public posting on the ISO's website a request for an Economic Study.

(ii) The ISO shall thereafter add any of its own proposals for Economic Studies. The ISO shall also develop a rough work scope and cost estimate for all requested Economic Studies, and develop preliminary prioritization based on the ISO's perceived regional

and/or, as coordinated with the applicable neighboring system, inter-area benefits to assist stakeholders in the prioritization of Economic Studies.

(iii) By no later than May 1 of each year, the ISO shall provide the foregoing information to the Planning Advisory Committee, and a Planning Advisory Committee meeting shall be held at which Economic Study proponents will provide an explanation of their request.

(iv) By no later than June 1 of each year, the ISO shall hold a meeting of the Planning Advisory Committee for the members of the Planning Advisory Committee to discuss, identify and prioritize, as further facilitated by the ISO's preparation of a straw priority list to be further discussed at such meeting, up to two (2) Economic Studies (the costs of which will be recovered by the ISO pursuant to Section IV.A of the Tariff) to be performed by the ISO in a given year taking into consideration their impact on the ISO budget and other priorities. The ISO may consider performing up to three (3) Economic Studies if a Public Policy Transmission Study will not be concurrently performed.

(v) The ISO and the Planning Advisory Committee may agree to hold additional meetings to further discuss and resolve any issue concerning the substance of the Economic Studies themselves and/or their prioritization.

(vi) If the Planning Advisory Committee, after discussions between the Planning Advisory Committee and ISO management, is not able to prioritize the Economic Studies to be performed by the ISO in a given year, any member of the Planning Advisory Committee must submit a request for Regional Planning Dispute Resolution Process pursuant to Section 12 of this Attachment, such request to be submitted no later than August 30, to resolve the issues concerning the substance of the Economic Studies themselves and/or their prioritization.

(vii) The ISO will issue a notice to the Planning Advisory Committee detailing the prioritization of the Economic Studies as identified by the Planning Advisory Committee or, if a request for Regional Planning Dispute Resolution Process is submitted pursuant to Section 4.1.(b)(vi), as determined through that Process.

The foregoing timelines are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee. The ISO will provide periodic updates on the status of Economic Studies to the Planning Advisory Committee.

Economic Study requests not within the three studies identified in Section 4.1(b)(iv) to be performed in a given year may be requested and paid for by the study proponent.

(c) Conduct of a Needs Assessment for Rejected ~~Non-Price Retirement Requests and~~ De-List Bids

(i) Where a Needs Assessment is underway for an area affected by a rejected Permanent De-List Bid or ~~Non-Price~~ Retirement De-List Bid~~Request~~, the Needs Assessment will represent the resource with the rejected Permanent De-List Bid or Retirement De-List Bid as being interconnected, but unavailable for reliability purposes~~, and the Non-Price Retirement Request as being retired~~ in the base representation being used to assess the system to identify reliability needs that must be addressed.

(ii) Where there is not a Needs Assessment underway for an area affected by a rejected Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~De-List Bid, the ISO will initiate a Needs Assessment for that area.

(iii) In the case of a rejected Static De-List Bid or Dynamic De-List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De-List Bids or Dynamic De-List Bids where the ISO believes that the initiation of such a study is warranted.

(iv) Prior to the start of each New Capacity Show of Interest Submission Window, the ISO shall present to the Reliability Committee the status of any prior rejected Dynamic De-List Bids, Static De-List Bids, Permanent De-List Bids or Retirement De-List Bids ~~de-list bids or Non-Price Retirement Requests~~ being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine resource adequacy, transmission adequacy, projected congestion levels and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Solutions in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

Specifically, the ISO shall incorporate or update information regarding resources in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request For Proposals, or (iii) have a financially binding obligation pursuant to a contract. The ISO will model out-of-service all submitted Retirement De-List Bids and submitted Permanent De-List Bids and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to (ii) or (iii) above, the prop onent of the market

response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff.

(g) Needs Assessment Support

For the development of the Needs Assessments, the ISO will coordinate with the PTOs and the Planning Advisory Committee to support the ISO's performance of Needs Assessments. To facilitate this support, the ISO will post on its website the models, files, cases, contingencies, assumptions and other information used to perform Needs Assessments. The ISO may establish requirements that any PTO or member of the Planning Advisory Committee must satisfy in order to access certain information used to perform Needs Assessments, due to ISO New England Information Policy and CEII constraints. The ISO may ask PTOs or Planning Advisory Committee members with special expertise to provide technical support or perform studies required to assess one or more potential needs that will be considered in the Needs Assessments process. These entities will provide, and the ISO will post on its website, the models, files, cases, contingencies, assumptions and other information used by those entities to perform studies. The ISO will post the draft results of any such Needs Assessment studies on its website. The ISO will convene meetings open to any representative of an entity that is a member of the Planning Advisory Committee to facilitate input on draft Needs Assessments studies and the inputs to those studies prior to the ISO's completion of a draft Needs Assessment report to be reviewed by the entire Planning Advisory Committee pursuant to Section 4.1(i) of this Attachment. All provisions of this subsection (g) relating to the provision and sharing of information shall be subject to the ISO-NE Information Policy.

(h) Input from the Planning Advisory Committee

Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to a Needs Assessment that were not identified in support of initiating the assessment, and to provide input on the Needs Assessment's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment.

(i) Publication of Needs Assessment and Response Thereto

The ISO shall report the results of Needs Assessments to the Planning Advisory Committee, subject to CEII constraints. Needs Assessments containing CEII will be posted on the ISO's password-protected website consistent with Section 2.4(d) of this Attachment. Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the needs described in the assessment. The ISO will also present the Needs Assessments in appropriate market forums to facilitate market responses. Where the ISO forecasts that a solution is needed to solve reliability criteria violations in three years or less from the completion of a Needs Assessment (unless the solution to the Needs Assessment will likely be a Market Efficiency Transmission Upgrade), and the requirements of Section 4.1(j) of this Attachment have been met or where there is only one Phase One Proposal or Stage One Proposal submitted in response to a public notice issued under Sections 4.3(a) or 4A.5(a) of this Attachment, respectively, or only one proposed solution that is selected to move on to Phase Two or Stage Two, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies, as described in Section 4.2 of this Attachment. Where the solution to a Needs Assessment will likely be a Market Efficiency Transmission Upgrade, or where the forecast year of need for a solution that is likely to be a Reliability Transmission Upgrade is more than three years from the completion of a Needs Assessment, the ISO will conduct a solution process based on a two-stage competition, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solution Studies Rather than Competitive Process for Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solution Studies in the circumstances described in Section 4.1(i) based on the solution's year of need:

(i) The ISO shall separately identify and post on its website an explanation of the reliability criteria violations and system conditions that the region has a time-sensitive need to solve within three years of the completion of the relevant Needs Assessment. The explanation shall be in sufficient detail to allow stakeholders to understand the need and why it is time-sensitive.

(ii) In deciding whether to utilize Solutions Studies, such that the regulated transmission solution will be developed through a process led by the ISO and built by the PTO(s), the ISO shall:

(A) Provide to the Planning Advisory Committee and post on its website a full and supported written description explaining the decision to designate a Participating Transmission Owner as the entity responsible for construction and ownership of the reliability project, including an explanation of other transmission or non-transmission options that the region considered but concluded would not sufficiently address the immediate reliability need, and the circumstances that generated the reliability need and an explanation of why that reliability need was not identified earlier.

(B) Provide a 30-day period during which comments from stakeholders on the posted description may be sent to the ISO, which comments will be posted on the website, as well.

(iii) The ISO shall maintain and post on its website a list of prior year designations of all projects in the limited category of transmission projects for which the PTO(s) was designated as the entity responsible for construction and ownership of the project following the performance of Solution Studies. The list must include the project's need-by date and the date the PTO(s) actually energized the project, i.e., placed the project into service. The ISO shall file such list with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year, when applicable.

NOVEMBER 18, 2015 | NEPOOL MARKETS COMMITTEE
WESTBOROUGH, MASSACHUSETTS

Capacity Resource Retirement Reform

Jeffrey McDonald
VICE PRESIDENT
MARKET MONITORING

Andrew Gillespie
PRINCIPAL ANALYST
MARKET DEVELOPMENT

Proposal to Address Concerns with Resource Retirements

Concerns from Internal and External Market Monitors:

- The limited ability for new capacity projects to react to the retirement of existing capacity resources.
- The limited ability to include in a capacity price (de-list bid) aspects that are relevant to a retirement decision.
- The effects of market power when capacity is physically or economically withheld.

Proposal:

- Modify the timing of the retirement process such that new capacity projects have a better opportunity to react.
- Improve the options available when retiring a capacity resource by creating priced Retirement De-List Bids and enhancing Permanent De-List Bids.

Market Signals - Timing

- Modify some of the FCA Deadlines:
  - **Move the SOI deadline later by approximately 2 months.**
    (from February to April)
  - **Require the submittal of all Permanent De-List Bids and Retirement Requests earlier, in March.**
    (from June to March for Permanent De-List Bids, and the former Non-Price Retirement Request deadline from October to March)
  - **After the March deadline the ISO will post information regarding capacity permanently exiting the market.**
    (*i.e.,* the MW quantity of submitted retirement requests and permanent de-list bids)
- Augments the capacity zone determination process.
- Indicates to new project sponsors that there is a potential need for capacity.

Retirement Options

After receiving the retirement determination notification for either a Permanent or Retirement De-List Bid, a participant may select one of the following:

1. **Use the IMM/FERC approved price** (default)
   - The IMM/FERC approved price is used for the retirement/permanent de-list bid.
   - Bid clears (resource retires) or not (is awarded a CSO) in the auction at this price.
2. **Unconditional Retirement**
   - A resource can (still) be retired without participating in the auction.
   - A proxy de-list bid would be entered into the auction to mitigate the market impact (physical withholding) only if the participant has a portfolio of other capacity resources that could be advantaged by the effect of the retirement on the auction outcome.
3. **Conditional Treatment**
   - A resource would exit the market at the participant's submitted price - if the clearing price is less than or equal to the submitted price.
   - A proxy de-list bid would be used to mitigate the market impact (economic withholding).

Retirement Options - *continued*

- Both Retirement and Permanent De-List Bids would provide a mechanism for participants to reflect the multiple-year nature of a capacity price associated with a resource's Retirement or Permanent De-List Bid.
- This proposed mechanism also provides a means for the Internal Market Monitor to review retirement requests.
- Proposal retains the ability for participants to unconditionally retire a resource.
- Proposal also allows a participant to avoid any under-compensation risk *without* unconditionally retiring.

ISO new england

memo

To: Participants Committee

From: Alex Kuznecow, Secretary, Markets Committee

Date: November 18, 2015

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 18, 2015 meeting. All Sectors had a quorum.

1. (Agenda Item 2) **NEPOOL GIS OPERATING RULES WORKING GROUP REFERRAL REQUEST**
   ACTION: REFERRED TO WORKING GROUP

   The following NextEra Energy Resources, LLC request was referred to the NEPOOL GIS Operating Rules Working Group:

   (1) Consider changes to the GIS and GIS Operating Rules to expand the transactions involving Reserve Certificates to also include all Certificates created for Zero Emissions Generators.

2. (Agenda Item 3) **WINTER RELIABILITY SOLUTION: WINTER PERIODS PRIOR TO JUNE 1, 2018 – 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 K to Market Rule 1 to appropriately address the Winter Reliability Solution cost allocation consistent with the Coordinated Transaction Scheduling 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.

   The motion was then voted. Based on a show of hands, the motion passed. 1 abstention within the Generation Sector, 2 abstentions within the Supplier Sector, 1 abstention within the Alternative Resources Sector, and 1 abstention within the End User Sector were recorded.

3. (Agenda Item 4) **RESOURCE RETIREMENT REFORMS**
   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 Resource Retirement Reforms 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 – Withdrawn** *(GDF SUEZ/Exelon/NextEra ("GEN") 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) Add a new paragraph to end of the ISO's proposed Section III.13.2.1.3.1.2 of Market Rule 1 as follows:

"Where the resource had requested a Retirement De-List Bid in the prior Forward Capacity Auction and obtained a Capacity Supply Obligation, the update can include a request to discontinue the Retirement De-List Bid and supporting information on the nature of resource investments that had to be undertaken in the absence of a retirement by the start of that Commitment Period, or other materially changed circumstances. If the IMM fails to provide its approval, the resource may submit a 205 request to the Commission seeking approval to discontinue retirement bids. Absent approval by the Internal Market Monitor or the Commission, the Retirement De-List Bid shall be entered into all subsequent Forward Capacity Auctions until it no longer receives a CSO and is retired."

(2) Revise the ISO's proposed Section III.13.2.5.2.1(b) of Market Rule 1 as follows:

"(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, or is discontinued pursuant to Section III.13.2.1.3.1.2, if all or part of a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the uncleared portion of the bid shall be entered into the qualification process for the following Forward Capacity Auction and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to Section III.13.1.2.3.1.5 and, updated as appropriate, shall be entered into that Forward Capacity Auction."

The Markets Committee proceeded to discuss potential changes to GEN Amendment #1 which included allowing a resource to have a onetime opportunity to discontinue its Retirement De-List Bid after the resource had requested a Retirement De-List Bid in a prior Forward Capacity Auction and obtained a Capacity Supply Obligation. After this discussion, the motion and second were withdrawn without objection by the Markets Committee.

(**Vote 2 – Failed** *(PSEG 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) Delete the ISO's proposed Section III.13.2.5.2.1(b) of Market Rule 1 as shown below:

"~~(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a Permanent De-List Bid or Retirement De-List Bid does not clear in the~~

~~Forward Capacity Auction (receives a Capacity Supply Obligation), the uncleared portion of the bid shall be entered into the qualification process for the following Forward Capacity Auction and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to Section III.13.1.2.3.1.5 and, updated as appropriate, shall be entered into that Forward Capacity Auction.~~"

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

(**Vote 3 – Failed** *(PSEG 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's proposed fourth sentence in Section III.13.1.2.3.1 of Market Rule 1 as follows:

"Permanent De-List Bids and Retirement De-List Bids may ~~not~~ be ~~modified~~ reduced or withdrawn within 14 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b)~~Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1~~."

(2) Revise the ISO's proposed last sentence in Section III.13.1.2.3.1.5(c) of Market Rule 1 as follows:

"Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.3.1~~4.1~~."

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

(**Vote 4 – Passed** *(GDF SUEZ/Exelon/NextEra ("GEN") 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's proposed Section III.13.2.5.2.1(b) of Market Rule 1 as follows:

"**Expected net operating profit**, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included. ~~Expenses associated with products or services reallocated or reassigned to other resources or other divisions of the Lead Market Participant or its Affiliates are not avoidable costs and may not be included.~~"

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

(**Vote 5 – Failed** *(GDF SUEZ/Exelon/NextEra ("GEN") 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) Revise the ISO's proposed Section III.13 of Market Rule 1, Appendix A to Market Rule 1 and Tariff Section I.2.2 in accordance with the GEN proposal which includes (1) a Retirement De-List Threshold (0.8*Net Cone), (2) May 1 Filing by Resource Owner of its Retirement De-List Bid under Section 205 of the Federal Power Act with the FERC, with the Resource Owner agreeing to accept the FERC's decision (no proxy de-list bids or two-settlement auctions) and (3) proposed language contained in GEN Amendment #2 (see GEN Amendment #3 (slides 5-8); proposed Tariff language).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 42.99% in favor. The individual Sector votes were Generation (17.13% in favor, 0% opposed, 3 abstentions), Transmission (1.56% in favor, 15.57% opposed, 0.5 abstention), Supplier (17.13% in favor, 0% opposed, 8 abstentions), Alternative Resources (7.19% in favor, 7.19% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.13% opposed), and End User (0% in favor, 17.13% opposed).

(**Vote 6 – Failed** *(GDF SUEZ/Exelon/NextEra ("GEN") Amendment #4)*) 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's proposed Section III.13 of Market Rule 1, Appendix A to Market Rule 1 and Tariff Section I.2.2 in accordance with the proposal contained in GEN Amendment #3 with the exclusion of the Retirement De-List Threshold (0.8*Net CONE).

The motion to amend the amended main motion was then voted. The motion to amend failed with a vote of 42.99% in favor. The individual Sector votes were Generation (17.13% in favor, 0% opposed, 3 abstentions), Transmission (1.56% in favor, 15.57% opposed, 0.5 abstention), Supplier (17.13% in favor, 0% opposed, 8 abstentions), Alternative Resources (7.19% in favor, 7.19% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.13% opposed), and End User (0% in favor, 17.13% opposed).

(**Vote 7 – Failed** *(GDF SUEZ/Exelon/NextEra ("GEN") Amendment #5)*) 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's proposed Section III.13 of Market Rule 1, Appendix A to Market Rule 1 and Tariff Section I.2.2 in accordance with the GEN proposal to allow a Resource Owner to retain the ability to submit a Non-Price Retirement Request (see GEN Amendment #5 (slide 10); proposed Tariff language).

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/Exelon/NextEra ("GEN") Amendment #6)*) 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's proposed Section III.13 of Market Rule 1, Appendix A to Market Rule 1 and Tariff Section I.2.2 in accordance with the GEN proposal which includes (1) GEN Amendment #5 and (2) add an additional process for approval of the Non-Price Retirement Request (see GEN Amendment #6 (slides 11-12); proposed Tariff language).

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

(**Vote 9 – 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) Revise the ISO's proposed Section III.13 of Market Rule 1, Appendix A to Market Rule 1 and Tariff Section I.2.2 in accordance with the NRG proposal (see NRG Amendment; proposed Tariff language).

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

(**Vote 10 – Failed**) The amended main motion was then voted. The amended main motion failed with a vote of 57.01% in favor. The individual Sector votes were Generation (0% in favor, 17.13% opposed), Transmission (15.57% in favor, 1.56% opposed, 0.5 abstention), Supplier (0% in favor, 17.13% opposed, 7 abstentions), Alternative Resources (7.19% in favor, 7.19% opposed, 1 abstention), Publicly Owned Entity (17.13% in favor, 0% opposed), and End User (17.13% in favor, 0% opposed).

ISO-NE Priced Retirement Proposal Alternatives for Enhanced Competition

November 18, 2015

We have the
energy
to make things better
... for you, for our investors
and for our stakeholders.

PSEG

We make things work for you.

What does it mean to submit a Priced Retirement Offer?

- This is an offer price at which a Resource seeks to retire.
- If the auction clearing price is below the Retirement De-List Bid, the resource will retire.
- The converse should be: If the auction clears at or above the Retirement De-list Bid, the unit does not retire.
- ISO Proposal requires a resource to stay on a "retirement track."
- We have heard no economic rationale for forcing a unit into a subsequent auction with a Retirement De-List Bid.
  - Allowing a resource to "reprice" its Retirement De-List Bid in subsequent auctions could still result in a forced retirement.
  - Proposal does not address what happens with subsequent Retirement De-list Bids if they are below Dynamic Delist Bid threshold Price
  - Proposal is unclear on the length of persistence Retirement Delist bids.

What is the Expectation for a Unit that Receives a CSO under its retirement offer?.

- A Retirement De-List Bid will generally include the cost of a capital upgrade under an amortization schedule that could not be considered as part of a Static Delist Bid

- The Retirement De-List Bid appropriately allows resource owners to amortize the cost of the upgrade in less than five years AND allows resource owners to forecast future expected capacity revenues AND future energy gross margins.
  - Static Delist Bids, while faced with similar investment decisions, are still prohibited from incorporating future expectations adequately.

- Should a resource that received a CSO under a Retirement De-List Bid still spend capital that was built into its retirement offer when it could be forced to retire in a subsequent auction?
  - The mere fact a bid must be submitted creates significant risk.

Amendment I: Eliminating the Retirement Track

- Proposal: A resource that submits a priced retirement offer in a Forward Capacity Auction and receives a CSO will be considered an Existing Resource in subsequent auctions.
  - Proposal: No future requirement to offer other than as an Existing Resource.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

~~(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the uncleared portion of the bid shall be entered into the qualification process for the following Forward Capacity Auction and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to Section III.13.1.2.3.1.5 and, updated as appropriate, shall be entered into that Forward Capacity Auction.~~

What is the Economic Rational to Require Offers to be Binding a Year Prior to the Auction?

- Rules that limit opportunities by restricting permissible choices are anti-competitive an impediment to efficient pricing.
  - ISO proposal extends notice for submitting a Retirement Offer 51 months prior to the commitment period.
  - The ISO proposed March submittal is now eleven months prior to the auction and seven months prior to the current requirement.
- Changing the timeline becomes an impediment for ensuring the highest level of competition in the auction.
- Goal should be to providing as much flexibility as possible to increase participation and enhances competition.

Amendment 2: Eliminating the Binding Retirement De-List Bid

III.13.1.2.3.1.

Permanent De-List Bids and Retirement De-List Bids may ~~not~~ be reduced ~~modified~~ or withdrawn within14 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4 (b) ~~Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1~~

III,13.1.2.3.1.5(c) Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.3.1~~4.1~~.

ISO-NE/IMM RETIREMENT REFORMS: GEN GROUP PRESENTATION

(GDF SUEZ ENERGY MARKETING N.A., EXELON CORPORATION, NEXTERA ENERGY RESOURCES, LLC)

NEPOOL Participants Committee

December 4, 2015

ISO-NE/IMM Proposal includes several improvements to the existing retirement review process

GEN Group Position on the ISO-NE/IMM Proposal

- **ISO-NE/IMM Proposal seeks to address several concerns**
  - **Timing – new resources are unaware of retirements**
  - **Bid construct – Permanent De-lists do not work**
  - **Market power**
- **ISO-NE/IMM proposals for first two items are good steps forward**
  - **Accelerated timing makes it more difficult to construct bids, but is workable**
  - **New "Retirement Bid" more accurately reflects actual decision-making inputs when retiring**
- **Recent modifications to IMM review process also helpful**
  - **Exit ramp, reallocated costs, capacity forecasts**

ISO-NE/IMM Proposal creates outcomes inconsistent with competitive markets

GEN Group Opposes ISO-NE/IMM Proposal

- **GEN Group's primary objections are in the proposed mechanisms to mitigate retirement bids:**
  - **ISO-NE/IMM proposal allows only protests to the IMM's judgment, which is substituted for the Resource Owner's business judgment for retiring a project**
  - **Use of IMM-determined proxy bids in the FCA does not allow market to determine price.**
  - **Potentially runs FCA twice, resulting in two different FCA clearing prices (that is, discriminatory pricing), with most existing resources receiving a lower clearing price (vintaging)**
- **Mitigating without any demonstration of exercise of market power**
- **Proposed rules are unlike those in any other market**

GEN Group Proposal builds off existing ISO-NE Tariff rules and ISO-NE/IMM's Proposal

GEN Group Proposal

- In March, using the same deadline as ISO-NE/IMM, Resource Owner notifies ISO-NE/IMM of its intent to retire
  - Resource Owner to file information supporting either (1) a price or (2) a non-price retirement
- IMM and Resource Owner vet the notice, retirement justification, internal risk/retirement analysis and related matters
  - Same 90 day process proposed by ISO-NE/IMM
- In June, upon receipt of the IMM Price determination, Resource Owner decides whether to commit to a non-price or price retirement and provides its final price and/or related information to ISO-NE to include in an Informational Filing
  - Resource Owner may convert a price retirement to a non-price retirement (but not the other way around)

GEN Group Proposal builds off existing ISO-NE Tariff rules and ISO-NE/IMM's Proposal

GEN Group Proposal, cont.

- **Following receipt of final worksheets to move forward with the priced bid, ISO-NE files the Resource Owner's price information with FERC as an Informational Filing**
  - **Final price by Resource Owner is less than or equal to original submittal (which allows the Resource Owner to take into account any feedback from the IMM)**
- **Similar process as the current Informational Filing of Static De-List Bids, with notable difference that it is the Resource Owner's worksheets that are included in this filing (all worksheets based on bid components detailed in the ISO-NE/IMM Proposal)**
- **IMM may challenge/protest Informational Filing**
- **Informational Filing result is entered in FCA**

GEN Group Proposal builds off existing ISO-NE Tariff rules and ISO-NE/IMM's Proposal

GEN Group Proposal, cont.

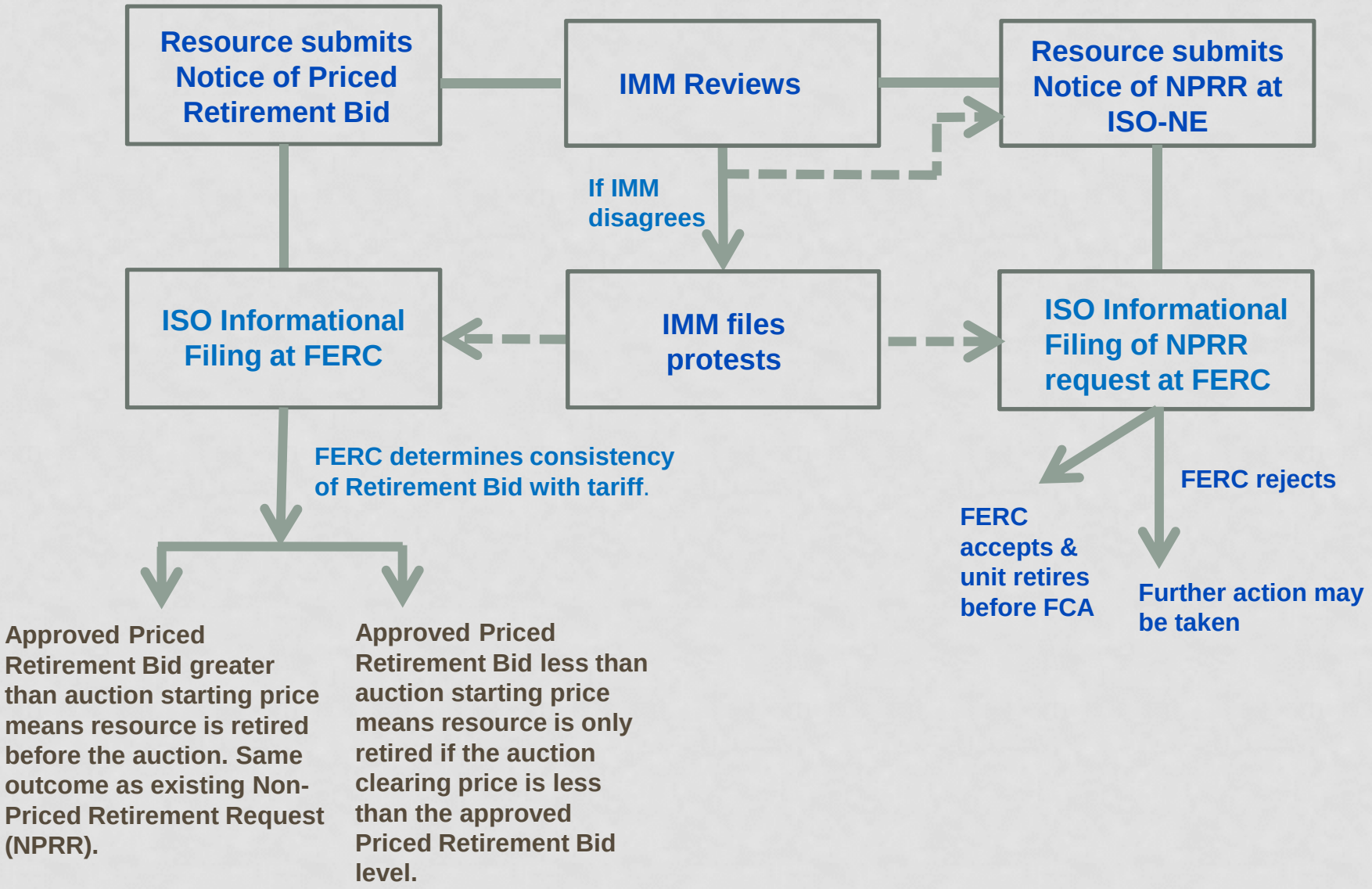
- For a Non-Price Retirement by a Resource Owner, the ISO-NE to include such election in the same Informational Filing as the price bids under same process
    - Supporting documentation for the Non-Price Retirement Request provided by the Resource Owner will be included in this filing
- IMM may challenge/protest the Non-Price Retirement element of the Informational Filing
- Inclusion in Informational Filing provides transparency on the Non-Price Retirement decision

GEN Group Proposal designed to balance concerns stated by the IMM, while still preserving competitive market signals

GEN Group Proposal Benefits

- Eliminates IMM's Proxy Bids and Two-Settlement Auctions
  - Retains one non-discriminatory auction
- Process timing is consistent with ISO-NE/IMM proposal
- Significant differences:
  - Cost estimates from the Resource Owners are included in the Informational Filing
  - Ability to submit a Non-Price Retirement Bid
    - Non-Price Retirement process similar to existing rules
- Market power concerns addressed

GEN Group Proposal



	IMM Proposal	GEN Proposal
Early notice of retirement	✓	✓
IMM Review	✓	✓
FERC Review	✓	✓
Differences:		
Non-priced retirement	⊘	✓
Filing burden	If both resource bid and IMM are competitive, FERC must accept IMM bid.	If resource bid is competitive, FERC can accept it.
FERC accepted bid binding	⊘	✓
Single clearing price	⊘	✓

GEN Group Proposal in Blue

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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.13.1.2.3.2.1.1.1~~2.~~ (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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.

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.

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

Common Costs are those costs associated with a Station that are avoided only by ~~(1)~~ the clearing of the Static De-List Bids, ~~or~~ the Permanent De-List Bids, or the Retirement 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 Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

Existing Demand 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).

~~**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-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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state,

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.13.1.2.3.1.5~~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.

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, 2018, 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.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily

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 or the Retirement 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.~~the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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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.13.1.1.1.3 or Section III.13.1.1.1.4, 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.13.1.1.1.6. 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.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement 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).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable

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~~ Retirement 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 two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity ~~Qualification~~ Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to 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) [Reserved.]

(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 the close of the New Capacity Show of Interest Submission Window~~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 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) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than ~~15~~ 20 Business Days before the Existing Capacity ~~Qualification~~Retirement 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 10~~5~~ Business Days before the Existing Capacity ~~Qualification~~Retirement 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, ~~or~~ a Retirement De-List Bid or a Non-Price Retirement Request 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 Retirement Package and 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 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Non-Price Retirement Requests in the Forward Capacity Auction must be noticed to the ISO no later than the Existing Capacity Retirement Deadline.

All Static De-List Bids, Export Bids and~~,~~ 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~~. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement ~~Qualification~~ Deadline, except as provided for in Section III.13.1.2.4.1. 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, except as provided for in Section~~s~~ III.13.1.2.3.1.1~~ and III.13.1.2.3.1.5.2~~. 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, ~~or~~ Retirement ~~Price~~ De-List Bid, or Non-Price Retirement Request for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. 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; neither a Permanent De-List Bid nor a Retirement De-List Bid or Non-Price Retirement Request may ~~not~~ be combined with any other type of de-list or export bid.

Static De-List Bids and~~,~~ 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 for a Forward Capacity Auction is $5.50/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.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, 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 qualification process. 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). 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 Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. ~~Permanent De-List Bids.~~ **[Reserved.]**

~~A Lead Market Participant with an Existing 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 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 at or 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 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 at or 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Permanent De-List Bids, Retirement De-List Bids and ~~Non-Price~~ Non-Price Retirement Requests ~~RequestDe-List Bids~~.

~~**III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.**~~

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ and Retirement De-List Bids ~~greater than 20 MW that are at or above the Dynamic De-List Bid Threshold~~ are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

(d) A Lead Market Participant with an Existing Capacity Resource seeking to retire without specifying a price at which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Non-Price Retirement Request, pursuant to Section III.13.1.2.3.1.5.2 and Section III.13.1.2.3.1.5.3.

~~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 submitted in accordance with the timing requirements of Section III.13.1.2.3.1.5.2 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 Permanent De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.1, a Non-Price Retirement Request may be submitted for the affected portion of the bid within 14 days after the issuance by the ISO of the qualification determination notification or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.~~

III.13.1.2.3.1.5.1~~3~~. Reliability Review of ~~Non-Price~~ Permanent De-List Bids and Retirement ~~Requests~~ De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) ~~Internal Market Monitor-approved~~ Permanent De-List Bids and ~~Internal Market Monitor-approved~~ Reitrement De-List Bids that are above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) . The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids ~~and Retirement De-List Bids~~ that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee no later than 30 days after the ISO submits to the Commission the retirement filing described in Section III.13.8.1(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than 10 Business Days after being informed that a resource is needed for relaiblity reasons pursuant to this Section III.13.1.2.3.1.5.1, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

~~(i)~~ For a Permanent De-List Bid above the Forward Capacity Auction Starting Price, the portion of the resource subject to the de-list bid -will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(ii)

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will be continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

~~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.13.1.2.3.1.5.2. 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.

III.13.1.2.3.1.5.3 Timing Requirements.

Where no Retirement De-List Bid has been submitted, the Non-Price Retirement Request must be submitted to the ISO by the Existing Capacity Retirement Deadline ~~between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction~~. In the case of a Retirement Price De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.~~1~~2, a Non-Price Retirement Request may be submitted

for the affected portion of the bid within 10 days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a)~~or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later~~.

III.13.1.2.3.1.5.4. 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. 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.13.1.2.3.1.5.5~~24.2~~ 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 and Retirement 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, or Retirement 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, or Retirement 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 of Stations having Common Costs. The Internal Market Monitor will review each Static De-List Bid, ~~and~~ Permanent De-List Bid and Retirement De-List Bids 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 establish an Internal Market Monitor-determined or Internal Market Monitor–approved price for 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 Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and~~,~~ Export Bids ~~at or Above the Dynamic De-List Bid Threshold~~, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid~~,~~ and each Export Bid at or above the Dynamic De-List Bid Threshold~~, and each Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (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).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List

Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor ~~because they are less than the Dynamic De-List Bid Threshold and/or equal to or less than 20 MW~~ shall ~~have an Internal Market Monitor-approved price equal to the submitted price and shall~~ be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each ~~of these~~ bid component~~s~~ must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make ~~such~~ the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted ~~has been entered from the prior Forward Capacity Auction~~ pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including ~~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, cash flows, opportunity costs, 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~~ Static De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a ~~Permanent~~ Static De-List Bid or an Export Bid is not consistent with the sum of the resource's net going forward costs~~,~~ plus reasonable expectations about the resource's Capacity Performance Payments~~,~~ plus reasonable risk premium assumptions~~, and~~ plus reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing. If an Internal Market Monitor-determined price is established for a ~~Permanent~~ Static De-List Bid or an Export Bid, 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~~c) shall include an explanation of the Internal Market Monitor-determined price 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.

~~**III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.**~~

~~If the Internal Market Monitor determines, after due consideration and consultation with a Lead Market Participant, that a Static De-List Bid is not consistent with a 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 Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing.~~

~~If an Internal Market Monitor-determined price is established for a bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-determined price 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.~~

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.

After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop an Internal Market Monitor-approved Permanent De-List Bid or Internal Market-Monitor ~~approved~~'s view of whether a Retirement De-List Bid ~~that~~ is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include the resource's explantions ~~an explanation of the Internal Market Monitor-approved price based on the Internal Market Monitor review~~ of the net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs ~~as determined by the Internal Market Monitor~~,

The filing described in Section III.13.8.1(a) ~~shalland~~ shall include an explanation of the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid submitted by a resource in a following year.

III.13.1.2.3.2.1.2.A Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor~~using ISO spreadsheets and forms provided~~, and may supplement this information with other evidence ~~as deemed necessary~~. A Static De-List Bid or~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ shall be considered consistent with the Existing 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 Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \text{ x } InfIndex}{(CQ_{Summer,}\, kw) \text{ x } (12, months)}$$

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_{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.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement ~~Price~~ De-List Bid that is to be reviewed by the Internal Market Monitor for purposes of creating the retirement determination notification described in Section III.13.1.2.4(a) shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any

data that are inconsistent with overall market conditions or do not reflect expected values.
The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model for purposes of creating the retirement determination notification described in Section III.13.1.2.4(a) and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity

prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with ~~Net CONE (or, if Net CONE is not yet published for the Capacity Commitment Period in question,~~ the Internal Market Monitor's estimate thereof~~)~~ in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life for purposes of creating the retirement determination notification described in Section III.13.1.2.4(a).

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
The supporting documentation must include a detailed description and sources of the Lead Market

Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor for purposes of creating the retirement determination notification described in Section III.13.1.2.4(a).

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

For purposes of creating the retirement determination notification described in Section III.13.1.2.4(a), t~~T~~he Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid ~~at or above the Dynamic De-List Bid Threshold~~, ~~or~~ Permanent De-List Bid, or Retirement De-List Bid at or 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 Capacity Resource that submits a Static De-List Bid, or an~~,~~ Export Bid~~ at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid~~at or 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.A 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 Capacity Resource submitting a Static De-List Bid or an~~,~~ Export Bid, ~~at or above the Dynamic De-List Bid Threshold, or~~ Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package or the Existing Capacity Retirement 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. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all ~~de-list bids~~Static 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.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, 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:

$$\frac{Cost\ Of\ Capital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.

(a) No later than 90 days after the Existing Capacity Retirement Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement Price De-List Bid concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(b) 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~~ and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review ~~subject~~ pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant -Elections~~ed Retirement or Conditional Treatment.~~

No later than ten Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the ~~IMM-approved Permanent De-List Bids and IMM-~~

~~approved Retirement De-List Bids~~ prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to submit a Non-Price Retirement to the ISO-NE, to be filed by ISO-NE with the Commission as described in Section III.13.8.1(a). ~~retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a)~~ T~~t~~he Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect to submit its Retirement De-List Bid to ISO-NE, which may be equal to or lower than the initial Retirement De-List Bid filed by the Lead Market Paricipant on the Existing Capacity Retirement Deadline, to be filed by ISO-NE with the Commission as described in Section III.13.8.1(a). ~~conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election~~ T~~t~~he Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

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

portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

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~~ Retirement 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.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

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) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

(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~~ 15 Business Days prior to the Existing Capacity ~~Qualification~~ Retirement 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.

Contract Description	**MW**	**Contract End Date**
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate – NE	Up to 225	10/31/2016
VJO: Highgate – NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II – NE	Up to 110	10/31/2016

associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted 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.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

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 a Commercial Operation Date before June 1, 2018, or a Demand Response Capacity Resource that cleared in the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period, shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2018. 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 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 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that neither a Permanent De-List Bid ~~Non-Price~~ nor a Retirement ~~Requests~~ De-List Bid 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 Section~~s~~ 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 or Retirement De-List Bids pursuant to Section III.13.1.2.3.1.5~~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

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~~ Retirement 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.13.1.4.2.5. 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~~ 20 Business Days before the Existing Capacity ~~Qualification~~ Retirement 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, Retirement 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

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.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

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, a Retirement Price 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, retire 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 and Retirement 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) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids, ~~and~~ Retirement De-List Bids, and Non-Price Retirement Requests. ~~If a Permanent De-List Bid at or above the Dynamic De-List Bid Threshold or a Static De-List Bid for which an Internal Market Monitor-determined price has not been established, 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~~Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such 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(b), 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, ~~and~~

Retirement De-List Bids, and Non-Price Retirement Requests 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.

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 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 FCM Deposit 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 Forward Capacity Auction Starting Price. If the FCM 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, financial assurance required prior to the auction pursuant to FAP 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 financial assurance required prior to the auction pursuant to FAP will be released 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.

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.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

~~The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.~~

~~New Capacity Show of Interest Submission Window~~	~~Existing Capacity Qualification Deadline~~	~~New Capacity Qualification Deadline~~	~~First Day of Forward Capacity Auction for the Capacity Commitment Period~~	~~Capacity Commitment Period Begins~~
~~For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007~~	~~Apr. 30, 2007~~	~~June 15, 2007~~	~~Feb. 4, 2008~~	~~June 1, 2010~~
~~Sept. 18, 2007 through Nov. 14, 2007~~	~~Mar. 14, 2008~~	~~Apr. 29, 2008~~	~~Dec. 8, 2008~~	~~June 1, 2011~~
~~July 15, 2008 through Sep. 16, 2008~~	~~Feb. 3, 2009~~	~~Feb. 17, 2009~~	~~Oct. 5, 2009~~	~~June 1, 2012~~

~~May 15, 2009 through July 14, 2009~~	~~Dec. 1, 2009~~	~~Dec. 15, 2009~~	~~Aug. 2, 2010~~	~~June 1, 2013~~
~~Mar. 15, 2010 through May 14, 2010~~	~~Oct. 1, 2010~~	~~Oct. 15, 2010~~	~~June 6, 2011~~	~~June 1, 2014~~
~~Mar. 1, 2011 through Mar. 14, 2011~~	~~Aug. 1, 2011~~	~~Aug. 15, 2011~~	~~Apr. 2, 2012~~	~~June 1, 2015~~
~~Jan. 3, 2012 through Jan. 17, 2012~~	~~June 1, 2012~~	~~June 15, 2012~~	~~Feb. 4, 2013~~	~~June 1, 2016~~
~~Feb. 14, 2013 through Feb. 28, 2013~~	~~June 3, 2013~~	~~June 17, 2013~~	~~Feb. 3, 2014~~	~~June 1, 2017~~

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 Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment~~tn~~ Period;

(c) the New Capacity Show of Interest Submission Window will be in ~~February~~ April~~(after the Forward Capacity Auction for the prior Capacity Commitment Period)~~, approximately four years and ~~three~~ two months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June, ~~just over~~approximately 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.

Existing Capacity Retirement Deadline	**New Capacity Show of Interest Submission Window**	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
March (X-4)	~~Feb.~~April (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

(v) Capacity associated with a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer 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 an offer 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 not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources ~~Submitted in Qualification~~.**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized ~~submitted~~ in the qualification process ~~(~~or as otherwise directed by the Commission~~)~~, shall be automatically bid into the appropriate round~~(s)~~ of the Forward Capacity Auction, such that each such resource's FCA 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, Retirement 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. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price or a Commission-approved Non-Price Retirement Request, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. ~~Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii).~~ In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). 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).

~~(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List~~

~~Bid, and shall be entered into the appropriate rounds of the Forwad Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).~~

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an ~~Permanent De-List Bid or~~ Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any ~~Static De-List Bid or Permanent De-List Bid converted into a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 and any~~ Retirement De-List Bid converted into a Non-Price Retirement Request and any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement Price De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification

Package, 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) **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 cleared amount of capacity determined by the System-Wide Capacity Demand Curve. 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~~A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, ~~or~~ Permanent De-list Bid, or Retirement De-List Bid shall ~~be~~ clear 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

using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

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 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 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, ~~and~~ Retirement De-List Bids and Rejected Non-Price Retirement Requests.

(a) Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid, or Retirement De-List Bid ~~or Proxy 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.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid ~~shall be entered~~ into the qualification process for the following Forward Capacity Auction as described in ~~and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to~~ Section III.13.1.2.3.1.5 ~~and, updated as appropriate, shall be entered into that Forward Capacity Auction~~.

~~(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.~~

~~(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the intial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).~~

~~(e) 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) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price, as adjusted pursuant to Sections III.13.2.7.9 and III.13.2.8, during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid 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) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.~~

(c) If the Commission rejects the resource owners' Non-Price Retirement Request filed under Section III.13.1.2.3.1.5.3, the resource shall be entered into the auction at the value as directed by the Commission, otherwise, the resource shall be entered into the auction at the Permanent De-List Bid or Retirement De-List Bid level approved by the Commission. Where these bid levels result in the resource obtaining a Capacity Supply Obligation, the resource owner may file under Section 205 of the Federal Power Act to recover any costs of supplying the Capacity Supply Obligation which exceed the applicable auction price and any litigation expenses involved in recovering those costs.

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 Review~~Reasons~~.

The ISO shall review each ~~Non-Price~~ Non-Price Retirement Request, Retirement -List Bid, 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~~ Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction~~; Proxy De-List Bids shall not be reviewed~~.

(a) The reliability review will be conducted first with Non-Price Retirement Requests and then in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. 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 criteria, or ISO New England System Rules. ~~Non-Price Retirement Requests and~~ Non-Price Retirement Requests and d~~D~~~~d~~e-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the ~~Non-Price Retirement Request or~~ 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 the Local Sourcing Requirement for a Capacity Zone.

(b) Where a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~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~~c) 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~~d) A resource that has a de-list bid rejected ~~pursuant to this Section III.13.2.5.2.5~~for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and~~. 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 a Capacity Supply Obligation~~s~~ as described in Section III.13.6.1.

(e~~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~~caused the ISO to reject the de-list bid

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~~f) If the reliability need that ~~prevented the de-listing of the resource~~caused the ISO to reject the de-list bid 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).~~ retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(~~e~~g) If a Permanent De-List Bid or a Retirement De-List Bid~~that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request~~ is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, 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~~h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list 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~~ De-List Bid or Permanent De-List Bid 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~~De-List Bid~~, 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, t~~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, or partial Retirement De-List Bid ~~would otherwise clear in the Forward Capacity Auction but the de-list bid~~ has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or 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. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

~~(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 or a Retirement 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 or III.13.1.2.3.1.5.1 or 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 Commission-approved Permanent D~~d~~e-L~~l~~ist B~~b~~id or Commission-approved Retirement 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 or Retirement 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 Commission-approved Permanent De-List Bid or Commission-approved Retirement 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 or Retirement De-List Bid was submitted. 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 or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b) . Resources that elect payment based on the ~~accepted~~ Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement 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 or Retirement 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.~~

(c~~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~~d) **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, or Retirement 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Resources.~~:~~

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section ~~III.13.2.5.2.5.3(a)(iii)~~III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section 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(b~~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 and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: ~~that~~ submitted ~~s~~ a ~~Non-Price~~ Retirement De-List Bid ~~Request~~ that was not included in the Forward Capacity Auction pursuant to Section ~~III.13.1.2.3.1.5~~ III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear~~ed~~ in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1~~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)~~. In~~f~~ the case of a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Bid rejected for reliability, ~~is approved after the resource has a Capacity Supply Obligation for the Cappacity Commitment Period for which the Non-Price Retirement Request was submitted~~ if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless 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 ~~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) A~~n~~ resource, or portion thereof, ~~Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request~~ that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~has been approved~~was submitted 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 no later than 15 days prior to commencement of the relevant Forward Capacity Auction. 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, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: ~~that has~~ submitted a ~~non-partial~~ Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.

III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid ~~has~~ clear~~ed~~ 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.~~ The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource ~~whose resource~~that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) 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~~-~~.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) ~~with a cleared non-partial Permanent De-List Bid~~ may ~~retire~~ be permanently de-listed ~~the resource~~ earlier than the Capacity Commitment Period for which its Permanent De-List Bid ~~has cleared~~was submitted 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 Retirement De-List Bid, 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 Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, 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 will not be rationed 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.13.2.7.8. [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 and Retirement 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 and Retirement 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 applicable Net CONE value; 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 applicable Net CONE value.

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 import-constrained 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)~~, plus the capacity of Proxy De-List Bids entered as as result of a retirement election pursuant to Section III.13.1.2.4.1(a))~~ minus capacity otherwise obligated in the 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 the max [applicable Net CONE value, Capacity Clearing Price for the Rest-of-Pool Capacity Zone] 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) [Reserved.]

(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. [Reserved.]

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition in an import-constrained Capacity Zone if there is not Inadequate Supply and 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), ~~plus the capacity of Proxy De-List Bids entered as as result of a retirement election pursuant to Section III.13.1.2.4.1(a),~~ minus capacity otherwise obligated for the Capacity Commitment Period, is less than the Local Sourcing Requirement; 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. 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

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, ~~Non-Price~~ Retirement ~~Request~~ De-List Bid 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~~ Retirement 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.13.1.1.1.2 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.13.4.2.1.2.1.1.2. 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~~ Retirement 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.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the

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 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make an informational filing with the Commission ~~pursuant to Section 205 of the Federal Power Act~~ describing the Permanent De-List Bids, ~~and~~ Retirement De-List Bids, and Non-Price Retirement Requests. The ISO will file the following information confidentially: the resource's determinations made ~~by the Internal Market Monitor~~ with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination; and for the Non-Price Retirement Requests, supporting documentation provided by the resource.~~.~~ The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids. If the Commission does not issue an order within 90 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction.~~and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.~~

(b) The Forward Capacity Auction shall be conducted using the determinations as approved 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).

(c~~b~~) 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~~ Static De-List Bids, Export Bids, and Administrative De-Lits Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids ~~de-list bids~~ 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 the Internal Market Monitor establishing an Internal Market Monitor-determined price for 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~~d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(~~a~~c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 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 of the filing that directs otherwise, the determinations contained in the informational filing 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).

~~(c) For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the ISO shall make an informational filing with the Commission no later than December 16, 2014 detailing its determination of the New Resource Offer Floor Price for each New Import Capacity Resource making a request and cost information submittal as described in Section III.13.1.3.5.6 and providing supporting documentation for each such determination. These determinations shall be filed confidentially with the Commission in the informational filing. Any comments or challenges to the determinations contained in the informational filing described in this Section III.13.8.1(c) must be filed with the Commission no later than December 23, 2014. If the Commission does not issue an order by January 15, 2015 that directs otherwise, the determinations contained in the informational filing shall be used in conducting the ninth 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 by January 15, 2015, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted 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 Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 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 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.]

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. 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 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. 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.

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 Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five B~~b~~usiness D~~d~~ays:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five B~~b~~usiness D~~d~~ays of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

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. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, 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 B~~b~~usiness D~~d~~ays following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, 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 must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)

1	2
2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
(b) refusing to make a Supply Offer, or 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 B~~b~~usiness D~~d~~ays prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. 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 B~~b~~usiness D~~d~~ays of the applicable Operating Day. The ISO shall correct the error

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

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.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, ~~and~~ Permanent De-List Bids, and Retirement Price De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(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 B~~b~~usiness D~~d~~ays to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3 Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

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.

III.A.22 [Reserved.]

III.A.23 Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1 Pivotal Supplier Test

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is

less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2 Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3 ~~Timing of~~ Pivotal Supplier Test ~~and~~ Notification of Results.

~~The pivotal supplier test will be calculated prior to the commencement of the Forward Capacity Auction, and no earlier than the deadline by which a supplier that has submitted a Non-Price Retirement Request for capacity must elect to retire for that auction.~~

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4 Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

~~**III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.**~~

~~The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:~~

~~If~~

~~The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than~~

~~the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement~~

~~De-List Bid, then~~

~~the Lead Market Participant will be found to have a portfolio benefit pursuant tofails the retirement portfolio test.~~

~~Where,~~

~~the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor- estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.~~

~~The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor- estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.~~

~~The Internal Market Monitor -estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve as specified in Section III.13.2.2.~~

~~For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.~~

~~For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control~~

~~under this Section III.A.4 and all capacity the control of which it has contracted to a third party.~~

nrg

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NRG Proposal

Resource Retirement Reforms

(Revision to 11.25.15 version are noted in red and underlined)

NEPOOL Markets Committee

NEPOOL Participants Committee Meeting
December 4, 2015

Resource Retirement Reforms

- ISO Objectives
- Concerns with ISO Proposal
- NRG Proposal
  - Options
- Questions

ISO objectives

- Allow market response to proposed existing resource retirement
  - Provide the marketplace information on **prospective** resource retirements prior to Show of Interest window deadline.
  - Notice of **prospective** resource retirements may incent investors, not already proposing a project for the instant FCA, to enter an Show Of Interest (SOI) based on interest generated by retirement notifications
- Provide mitigation of perceived exercise of market power from existing resource retirement

Concerns with ISO Proposal

- Binding nature of Price Retirement bid submission reduces an Existing Resource owner's ability to effectively manage its resources in the FCM
- Imposes significant risk on resource owners by not allowing Price Retirement bids to fully reflect latest information, market conditions or other options on capital deployment
- Creates and further exacerbates discriminatory treatment of Existing Resources in FCA through its inability to reflect its cost for market exit closer to or in the FCA
- Moves the FCM farther away from functioning as a "market" where all resources compete in the auction directly
- Reduces consumer benefits by forcing reduced competition in the auction
- May lead to premature retirement of existing resources

NRG Retirement Proposal

- March 1 - Retirement notification provided to ISO, including cost workbook
- March 1 to June 1- Market Participant and IMM work to reach consensus on retirement bid price
- June 1 – IMM provides Market Participant draft Retirement Bid determination
  - Market Participant reviews and provides feedback to IMM on draft
- June 15 – IMM produces final Retirement Bid determination
  - Market Participant may file a 206 with the Commission if they disagree with IMM determined price
- No Later than 127 days before the FCA the IMM shall provide Retirement Determination Notification (RDN) indicating the IMM accepted, or Commission determined resource retirement price and its opinion that a resource retirement has a high probability of failing the IMM's portfolio test.

NRG proposal supports ISO desire for early notification and priced retirement

NRG Retirement Proposal

- Mitigation aspects of proposal is only applicable to Market Participant with greater than one resource in its portfolio
- NRG proposal satisfies the ISO objectives of:
  - Priced Resource Retirement
  - Mitigation of Market Power
  - Providing notice to market of potential retirements prior to Show Of Interest window
- Provides strong incentives that remove any benefit from the exercise of market power
- Mitigates the Actor and NOT the Market

NRG proposal mitigates incentives to exercise of market power

NRG's Proposal – Resource Retirement

- **Option 1"Accept IMM or Commission Determined Price"**
  - Within 7 days of RDN Market Participant notifies ISO it will accept IMM accepted or Commission determined price
  - Resource entered in FCA at the Market Participant accepted price
  - Retirement bid will allow CAPEX costs to be recovered over economic evaluation period, not to exceed 5 years
  - Resource awarded CSO if FCA clearing price is above accepted bid price
  - Resource awarded CSO in FCA participates in future auctions as an existing resource
  - If FCA clearing price is below accepted price the resource is not awarded a CSO and is retired from FCM

Option 1 provides "priced" Resource Retirement to market

NRG's Proposal – Resource Retirement

- **Option 2 "Lower or Withdraw Price Retirement Bid"**
  - Within 7 days of RDN Market Participant notifies ISO it has lowered its bid price below the IMM or Commission determined price from Option 1 or has fully withdrawn its Price Retirement bid
  - Resource participates in FCA with its revised retirement bid or as Existing Resource if retirement bid is withdrawn
  - Awarded CSO in FCA if retirement bid was withdrawn or FCA clearing price was above revised retirement bid
  - If awarded a CSO resource will participate in future FCA as Existing Resource
  - If FCA clearing price is below revised retirement bid resource is retired from FCM

Option 2 provides resource owner needed risk mitigation and consumer benefit

NRG's Proposal – Resource Retirement

- **Option 3 "Conditional Retirement Bid"**
  - Within 7 days of RDN Market Participant notifies ISO of conditional resource retirement
  - Step 1:
    - FCA is run with all qualified resources, including retiring resource at participant-submitted price, to establish the FCA clearing price
    - If FCA clears above Market Participant submitted retirement bid no further actions required. Resource is awarded CSO
    - FCA Clearing Price from Step 1 is applied to all cleared Resources, except Resources under the price lock from previous FCA
    - If FCA clears below IMM or Commission determined bid price ,resource retires from FCM. No CSO awarded. No further actions
    - If FCA clears between a Market Participant's retirement bid and IMM or Commission determined bid price the resource retires. No CSO awarded.
      - If the IMM determines a resources owner's portfolio benefited from its resource retirement then move to Step 2

NRG's Proposal – Resource Retirement

—Option 3 "Conditional Retirement Bid" Con't

- Step 2:
  - Rerun FCA including in the supply stack conditionally retired resources that were not awarded a CSO in the FCA, and for which the IMM deemed to have been provided benefit to a resources owner's portfolio,
  - Retired resource entered into mitigation price run at the IMM or Commission determined bid price
  - If the mitigation price determined in Step 2 FCA run is less than the FCA Clearing Price in Step 1, then apply that price to the resources in the portfolio associated with a conditionally retired resource
- The FCA Clearing Price (Step 1) reflects the actual supply situation in the FCA, ie, the resource is retired
- Price distortion in market is avoided
- Strong incentives exist to prevent the exercise of market power
- If market power is suspected the Actor is mitigated NOT the Market

Option 3 provides strong incentives to prevent exercise of market power

NRG's Proposal – Portfolio Test

- Currently the IMM Portfolio test has no materiality component
- Assumes Market Participant would be willing to exercise market power if the financial gain to its portfolio is $0.01.
- Portfolio test should apply a minimum threshold trigger where a Market Participant would "fail" the portfolio test if portfolio revenues , as a result of its resource retirement, increase by the greater of than 5%.

NRG Proposal lowers risk "false positive" in market revenue screen

NRG's Proposal

Questions ?

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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.13.1.2.3.2.1.1.1~~2.~~ (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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.

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.

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

Common Costs are those costs associated with a Station that are avoided only by ~~(1)~~ the clearing of the Static De-List Bids, ~~or~~ the Permanent De-List Bids, or the Retirement 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 Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, 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 Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

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

Existing Demand 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).

~~**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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been

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.13.1.2.3.1.5~~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.

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, 2018, 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.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily

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 or the Retirement 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~~.

III.13.1.1.2.5.4	New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.
III.13.1.1.2.6	[Reserved.]
III.13.1.1.2.7	Opportunity to Consult with Project Sponsor.
III.13.1.1.2.8	Qualification Determination Notification for New Generating Capacity Resources.
III.13.1.1.2.9	Renewable Technology Resource Election.
III.13.1.1.2.10	Determination of Renewable Technology Resource Qualified Capacity.
III.13.1.2	Existing Generating Capacity Resources.
III.13.1.2.1	Definition of 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.
III.13.1.2.2.1.2	Winter Qualified Capacity.
III.13.1.2.2.2	Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.
III.13.1.2.2.2.1	Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.
III.13.1.2.2.2.2	Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.
III.13.1.2.2.3	Qualified Capacity Adjustment for Partially New and Partially Existing Resources.
III.13.1.2.2.4	Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity ~~Qualification~~ Retirement Deadline.
III.13.1.2.2.5	Adjustment for Certain Significant Increases in Capacity.
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.
III.13.1.2.3	Qualification Process for Existing Generating Capacity Resources.

III.13.1.2.3.1	~~———~~Existing Capacity Retirement Package and Existing Capacity Qualification Package.
III.13.1.2.3.1.A	Dynamic De-List Bid Threshold.
III.13.1.2.3.1.1	Static De-List Bids.
III.13.1.2.3.1.2	[Reserved.]~~Permanent De-List Bids.~~
III.13.1.2.3.1.3	Export Bids.
III.13.1.2.3.1.4	Administrative Export De-List Bids.
III.13.1.2.3.1.5	~~———Non-Price~~ Permanent De-List Bids and Retirement ~~Request~~De-List Bids.
III.13.1.2.3.1.5.1	Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.~~Description of Non-Price Retirement Request.~~
~~III.13.1.2.3.1.5.2~~	~~Timing Requirements.~~
~~III.13.1.2.3.1.5.3~~	~~Reliability Review of Non-Price Retirement Requests.~~
~~III.13.1.2.3.1.5.4~~	~~Obligation to Retire.~~
III.13.1.2.3.1.6	Static De-List Bids, ~~and~~ Permanent De-List Bids and Retirement De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.
III.13.1.2.3.1.6.1	Submission of Cost Data.
III 13.1.2.3.1.6.2	[Reserved.]
III 13.1.2.3.1.6.3	Internal Market Monitor Review of Stations having Commission Costs.
III.13.1.2.3.2	Review by Internal Market Monitor of Bids from Existing Capacity Resources.
III.13.1.2.3.2.1	Static De-List Bids~~,~~ and Export Bids ~~at or Above the Dynamic De-List Bid Threshold~~, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.
III.13.1.2.3.2.1.1	Internal Market Monitor Review of De-List Bids.
III.13.1.2.3.2.1.1.1~~.~~	Review of ~~Permanent~~ Static De-List Bids and Export Bids.
III.13.1.2.3.2.1.1.2~~.~~	Review of Permanent De-List Bids and Retirement~~Static~~ De-List Bids.
III.13.1.2.3.2.1.2.A	Static De-List Bid and Export Bid Net Going Forward Costs.

III.13.1.2.3.2.1.2.B	Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.
III.13.1.2.3.2.1.2.C	Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.
III.13.1.2.3.2.1.3	Expected Capacity Performance Payments.
III.13.1.2.3.2.1.4	Risk Premium.
III.13.1.2.3.2.1.5	Opportunity Costs.
III.13.1.2.3.2.2	[Reserved.]
III.13.1.2.3.2.3	Administrative Export De-List Bids.
III.13.1.2.3.2.4	Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.
III.13.1.2.3.2.5	Static De-List Bid Incremental Capital Expenditure Recovery Schedule.
III.13.1.2.4	Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.
III.13.1.2.4.1	Participant-Elected Retirement or Conditional Treatment.
III.13.1.2.5	Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.
III.13.1.3	Import Capacity.
III.13.1.3.1	Definition of Existing Import Capacity Resource.
III.13.1.3.2	Qualified Capacity for Existing Import Capacity Resources.
III.13.1.3.3.A	Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.
III.13.1.3.3.B	Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.
III.13.1.3.4	Definition of New Import Capacity Resource.
III.13.1.3.5	Qualification Process for New Import Capacity Resources.
III.13.1.3.5.1	Documentation of Import.
III.13.1.3.5.2	Import Backed by Existing External Resources.
III.13.1.3.5.3	Imports Backed by an External Control Area.

III.13.2.3.2	Step 2: Compilation of Offers and Bids.
III.13.2.3.3	Step 3: Determination of the Outcome of Each Round.
III.13.2.3.4	Determination of Final Capacity Zones.
III.13.2.4	Forward Capacity Auction Starting Price and the Cost of New Entry.
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.
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 and Retirement De-List Bids.
III.13.2.5.2.2	Static De-List Bids and Export Bids.
III.13.2.5.2.3	Dynamic De-List Bids.
III.13.2.5.2.4	Administrative Export De-List Bids.
III.13.2.5.2.5	~~Bids Rejected for~~ Reliability Reviewasons.
III.13.2.5.2.5.1	Compensation for Bids Rejected for Reliability Reasons.
III.13.2.5.2.5.2	Incremental Cost of Reliability Service From Permanent De-List Bid and ~~Non-Price~~ Retirement ~~Request~~De-List Bid Resources.
III.13.2.5.2.5.3	Retirement and Permanent De-Listing of Resources.
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.
III.13.2.6	Capacity Rationing Rule.
III.13.2.7	Determination of Capacity Clearing Prices.
III.13.2.7.1	Import-Constrained Capacity Zone Capacity Clearing Price Floor.
III.13.2.7.2	Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.
III.13.2.7.3	Capacity Clearing Price Floor.
III.13.2.7.3A	Treatment of Imports.

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.13.1.1.1.3 or Section III.13.1.1.1.4, 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.13.1.1.1.6. 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.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement 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).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable

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~~ Retirement 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 two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity ~~Qualification~~ Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to 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) [Reserved.]

(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 the close of the New Capacity Show of Interest Submission Window~~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 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) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than ~~15~~ 20 Business Days before the Existing Capacity ~~Qualification~~Retirement 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 10~~5~~ Business Days before the Existing Capacity ~~Qualification~~Retirement 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, or a Retirement 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 Retirement Package and 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 15~~0~~ Business Days before the Existing Capacity ~~Qualification~~ Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and~~,~~ 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~~. Permanent De-List Bids and Retirement De-List Bids may be withdrawn after the Existing Capacity Retirement ~~Qualification~~ Deadline, except as provided for in Section III.13.1.2.4.1. 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, except as provided for in Section~~s~~ III.13.1.2.3.1.1~~ and III.13.1.2.3.1.5.2~~. 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, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. 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; neither a Permanent De-List Bid nor a Retirement De-List Bid may ~~not~~ be combined with any other type of de-list or export bid.

Static De-List Bids and~~,~~ 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 for a Forward Capacity Auction is $5.50/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.

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, 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 qualification process. 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). 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 Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(c), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. ~~Permanent De-List Bids.~~ **[Reserved.]**

~~A Lead Market Participant with an Existing 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 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 at or 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 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 at or 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 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, an Intermittent Settlement Only Resource or a Renewable Technology 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 qualification process. 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 shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Permanent De-List Bids and ~~Non-Price~~ Retirement ~~Request~~De-List Bids.

~~**III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.**~~

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids greater than 20 MW that are at or above the Dynamic De-List Bid Threshold and Retirement De-List Bids greater than 20 MW that are at or 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. Once submitted, ~~no~~ Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

~~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 submitted in accordance with the timing requirements of Section III.13.1.2.3.1.5.2 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 Permanent De-List Bid for which an Internal Market Monitor-determined price has been established pursuant to Section III.13.1.2.3.2.1.1.1, a Non-Price Retirement Request may be submitted for the affected portion of the bid within 14 days after the issuance by the ISO of the qualification determination notification or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.~~

III.13.1.2.3.1.5.1~~3~~. Reliability Review of ~~Non-Price~~ Permanent De-List Bids and Retirement ~~Requests~~ De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-approved Permanent De-List Bids and Internal Market Monitor-approved ~~Reitrement~~Retirement De-List Bids that are above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) . The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee no later than 30 days after the ISO submits to the Commission the retirement filing described in Section III.13.8.1(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than 10 Business Days after being informed that a resource is needed for ~~relaiblity~~reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

~~(i)~~ For a Permanent De-List Bid above the Forward Capacity Auction Starting Price, the portion of the resource subject to the de-list bid -will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(ii)

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will be continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

~~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 and Retirement 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, or Retirement 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, or Retirement 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 of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, ~~and~~ Permanent De-List Bid and Retirement De-List Bids 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 establish an Internal Market Monitor-determined or Internal Market Monitor–approved price for 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 Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and~~,~~ Export Bids~~ at or Above the Dynamic De-List Bid Threshold~~, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid~~,~~ and each Export Bid at or above the Dynamic De-List Bid Threshold~~, and each Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (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).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant, the Internal Market Monitor shall review each such bid above the Dynamic De-List Bid Threshold if the sum of all such bids above the Dynamic De-List Bid Threshold is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor because they are less than the Dynamic De-List Bid Threshold and/or equal to or less than 20 MW shall have an Internal Market Monitor-approved price equal to the submitted price and shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each ~~of these~~ bid component~~s~~ must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make ~~such~~ the requisite determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including ~~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, cash flows, opportunity costs, 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~~ Static De-List Bids and Export Bids.

If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that a ~~Permanent~~ Static De-List Bid or an Export Bid is not consistent with the sum of the resource's net going forward costs~~,~~ plus reasonable expectations about the resource's Capacity Performance Payments~~,~~ plus reasonable risk premium assumptions~~, and~~ plus reasonable opportunity costs, then the Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing. If an Internal Market Monitor-determined price is established for a ~~Permanent~~ Static De-List Bid or an Export Bid, 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~~c) shall include an explanation of the Internal Market Monitor-determined price 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.

~~**III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.**~~

~~If the Internal Market Monitor determines, after due consideration and consultation with a Lead Market Participant, that a Static De-List Bid is not consistent with a 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 Internal Market Monitor will establish an Internal Market Monitor-determined price for the bid that is consistent with its determination of the foregoing.~~

~~If an Internal Market Monitor-determined price is established for a bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-determined price 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.~~

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.
After due consideration and consultation with the Lead Market Participant, as appropriate, the Internal Market Monitor shall develop an Internal Market Monitor-approved Permanent De-List Bid or Internal Market-Monitor-approved Retirement De-List Bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-approved price based on the Internal Market Monitor review of the net present value of the resource's expected cash flows, reasonable expectations about the resource's Capacity Performance Payments, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.A Static De-List Bid and Export Bid Net Going Forward Costs.
The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor~~using ISO spreadsheets and forms provided~~, and may supplement this information with other evidence~~ as deemed necessary~~. A Static De-List Bid or~~,~~ Export Bid at or above the Dynamic De-List Bid Threshold~~, or~~

~~Permanent De-List Bid at or above the Dynamic De-List Bid Threshold~~ shall be considered consistent with the Existing 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 Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \text{ x } InfIndex}{(CQ_{Summer,}\, kw) \text{ x } (12, months)}$$

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_{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.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market

Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values.
The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included. Expenses associated with products or services reallocated or reassigned to other resources or other divisions of the Lead Market Participant or its Affiliates are not avoidable costs and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on

the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with Net CONE (or, if Net CONE is not yet published for the Capacity Commitment Period in question, the Internal Market Monitor's estimate thereof) in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting

the weighted average cost of capital for the Existing Capacity Resource adjusted for risk. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk. If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an~~,~~ Export Bid ~~at or above the Dynamic De-List Bid Threshold~~, ~~or~~ Permanent De-List Bid, or Retirement De-List Bid at or 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 Capacity Resource that submits a Static De-List Bid, or an~~,~~ Export Bid~~ at or above the Dynamic De-List Bid Threshold, or Permanent De-List Bid~~at or 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.A 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 Capacity Resource submitting a Static De-List Bid or an~~,~~ Export Bid, ~~at or above the Dynamic De-List Bid Threshold, or~~ Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the 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. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all ~~de-list bids~~Static 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.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, 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:

$$\frac{Cost\ Of\ Capital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. **Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity.**

(a) (a) No later than 90 days after the Existing Capacity Retirement Deadline, the ISO shall send a draft notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement De-List Bid concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2 and will include the IMM's opinion that resource retirement has a high probability of failing the portfolio test. . This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(b) No later than 105 days days after the Existing Capacity Retirement Deadline, the ISO shall send a final notification to the Lead Market Participant that submitted each Permanent De-List Bid and Retirement De-List Bid concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2 and will include the IMM's opinion that resource retirement has a high probability of failing the portfolio test . This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5.

(bc) 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 ,Retirement, Permanent De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2 or reflecting in the case of a Retirement bid a Commission determine

price. The qualification determination shall not include the results of the reliability review ~~subject~~ pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than -seven Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(~~a~~c), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) or Section III.13.1.2.4 (c). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) or Section III.13.1.4.1 (c), the IMM-approved Permanent De-List Bids and IMM-approved Retirement De-List Bids provided in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(c) A Lead Market Participant may lower the price of any price-quantity pair of a Retirement De-List Bid, below the IMM accepted or IMM or Commission detetmined price, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

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 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 established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification

requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

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~~ Retirement 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.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

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) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

(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~~ 15 Business Days prior to the Existing Capacity ~~Qualification~~ Retirement 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.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025

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.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted 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.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

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 a Commercial Operation Date before June 1, 2018, or a Demand Response Capacity Resource that cleared in the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period, shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June

1, 2018. 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 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 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that neither a Permanent De-List Bid ~~Non-Price~~ nor a Retirement ~~Requests~~ De-List Bid 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 Section~~s~~ 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 or Retirement De-List Bids pursuant to Section III.13.1.2.3.1.5~~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~~ Retirement 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.

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~~ 20 Business Days before the Existing Capacity ~~Qualification~~ Retirement 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, Retirement 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

serving entity's Capacity Load Obligation 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.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

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, a Retirement 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, retire 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) Quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement 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) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids. ~~If a Permanent De-List Bid at or above the Dynamic De-List Bid Threshold or a Static De-List Bid for which an Internal Market Monitor-determined price has not been established, 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~~Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such 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(c), 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, and Retirement 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.

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 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 FCM Deposit 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 Forward Capacity Auction Starting Price. If the FCM 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, financial assurance required prior to the auction pursuant to FAP 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

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.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

~~The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.~~

~~New Capacity Show of Interest Submission Window~~	~~Existing Capacity Qualification Deadline~~	~~New Capacity Qualification Deadline~~	~~First Day of Forward Capacity Auction for the Capacity Commitment Period~~	~~Capacity Commitment Period Begins~~

~~For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007~~	~~Apr. 30, 2007~~	~~June 15, 2007~~	~~Feb. 4, 2008~~	~~June 1, 2010~~
~~Sept. 18, 2007 through Nov. 14, 2007~~	~~Mar. 14, 2008~~	~~Apr. 29, 2008~~	~~Dec. 8, 2008~~	~~June 1, 2011~~
~~July 15, 2008 through Sep. 16, 2008~~	~~Feb. 3, 2009~~	~~Feb. 17, 2009~~	~~Oct. 5, 2009~~	~~June 1, 2012~~
~~May 15, 2009 through July 14, 2009~~	~~Dec. 1, 2009~~	~~Dec. 15, 2009~~	~~Aug. 2, 2010~~	~~June 1, 2013~~
~~Mar. 15, 2010 through May 14, 2010~~	~~Oct. 1, 2010~~	~~Oct. 15, 2010~~	~~June 6, 2011~~	~~June 1, 2014~~
~~Mar. 1, 2011 through Mar. 14, 2011~~	~~Aug. 1, 2011~~	~~Aug. 15, 2011~~	~~Apr. 2, 2012~~	~~June 1, 2015~~
~~Jan. 3, 2012 through Jan. 17, 2012~~	~~June 1, 2012~~	~~June 15, 2012~~	~~Feb. 4, 2013~~	~~June 1, 2016~~
~~Feb. 14, 2013 through Feb. 28, 2013~~	~~June 3, 2013~~	~~June 17, 2013~~	~~Feb. 3, 2014~~	~~June 1, 2017~~

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 Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment~~tn~~ Period;

(c) the New Capacity Show of Interest Submission Window will be in ~~February~~ April~~(after the Forward Capacity Auction for the prior Capacity Commitment Period)~~, approximately four years and ~~three~~ two months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June, ~~just over~~approximately 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.

Existing Capacity Retirement Deadline	**New Capacity Show of Interest Submission Window**	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
March (X-4)	~~Feb.~~April (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.1.11 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 (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), 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.

(v) Capacity associated with a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than 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 or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer 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 an offer 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 not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources ~~Submitted in Qualification~~.**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized ~~submitted~~ in the qualification process ~~(~~or as otherwise directed by the Commission~~)~~, shall be automatically bid into the appropriate round~~(s)~~ of the Forward Capacity Auction, such that each such resource's FCA 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, Retirement 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. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) shall be bid into the Forward Capacity Auction at the ~~Interanl~~Internal Market Monitor approved or Commission approved price. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(b) shall ~~not~~ be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Permanent De-List Bids and Retirement De-List Bids, if the Market Participant withdrew the bid pursuant to Section III.13.1.2.4.1 (c), then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). 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).

(ii) For Permanent De-List Bids and Retirement De-List Bids subject to election under Section III.13.1.2.4.1(b), the ISO will enter the capacity associated with Permanent De-List Bids and Retirement De-List Bids, at the Market Participant submitted Permanent De-List Bid and Retirement De-List Bid price , into the auction such that the capacity associated with the Permanent De-List Bid and Retirement De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Permanent De-List Bid and Retirement De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is

removed from the aggregate supply curves.

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(a) If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor approved or Commission-approved Permanent De-List Bid or Internal Market Monitor or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, \the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(b) In the instance where the Internal Market Monitor approved or Commission-approved Permanent De-List Bid or Internal Market Monitor or Commission-approved Retirement De-List Bid is less than the de-list bid submitted by the Lead Market Participant, the Forward Capacity Auction has cleared at a price greater than the Internal Market Monitor approved or Commission-approved Permanent De-List Bid or Internal Market Monitor or Commission-approved Retirement De-List Bid price and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24 then the ISO shall execute a mitigation price run of the auction clearing engine to determine a mitigation price for the capacity resources associated with the portfolio, for each Market Participant identified in the portfolio test, conducted pursuant to Section III.A.24. The mitigation price auction run will include in the aggregate supply stack all capacity resources awarded a CSO at the Forward Capacity Auction Clearing Price, as determined pursuant to Section III.13.2, and any resources of the Market Participant with a cleared retirement bid that failed the portfolio test pursuant to Section III.A.24.

(c) The mitigation price auction determined pursuant to Section III.13.2.3.2(b)(ii)(b), if less than the Forward Capacity Clearing Price, as determined pursuant to Section III.13.2, will apply to resource portfolio of a Market Participant subject to Section III.13.2.3.2(b)(ii)(b).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then

the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an ~~Permanent De-List Bid or~~ Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any ~~Static De-List Bid or Permanent De-List Bid converted into a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 and any~~ Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, 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

(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 cleared amount of capacity determined by the System-Wide Capacity Demand Curve. 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~~A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, ~~or~~ Permanent De-list Bid, or Retirement De-List Bid shall ~~be~~ clear 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 and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. 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.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $14.04/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2018 is $11.08/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e), except that the energy and ancillary services offset will be adjusted using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

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 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 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 and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid, Retirement 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.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the uncleared portion of the bid shall be entered into the qualification process for the following Forward Capacity Auction and treated as a Permanent De-List Bid or Retirement De-List Bid submitted pursuant to Section III.13.1.2.3.1.5 and, updated as appropriate, shall be entered into that Forward Capacity Auction.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in clearing the Forward Capacity Auction: (1) if any Permanent De-List Bid or Retirement De-List Bid with a price greater than the Internal Market Monitor approved or Commission approved price, entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b), clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) and (2) the Internal Market Monitor has found, pursuant to Section III. A.24, the capacity portfolio of a the Lead Market Participant associated with the cleared Permanent De-List Bid or Retirement De-List Bid under Section III.13.1.2.4.1(b), has benefit from the retirement. The auction process -(but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated to determine the mitigation price that will be applicable for the capacity resources associated -with the capacity portfolio of a the Lead Market Participant associated with the cleared Permanent De-List Bid or Retirement De-List Bid under Section III.13.1.2.4.1(b), that the Internal Market Monitor has determine to have benefited from the retirement of its resource.

(e) 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) that receive a Capacity Supply Obligation as a result of the clearing the Forward Capacity Auction shall be paid the Capacity Clearing Price, as adjusted pursuant to Sections III.13.2.7.9 and III.13.2.8, during the associated Capacity Commitment Period.

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 Review~~Reasons~~.

The ISO shall review each ~~Non-Price~~ Retirement ~~Request~~De-List Bid, 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.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. 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 criteria, or ISO New England System Rules. ~~Non-Price Retirement Requests and~~ D~~d~~e-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected 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 the Local Sourcing Requirement for a Capacity Zone.

(b) Where a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~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~~c) ___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~~d) A resource that has a de-list bid rejected ~~pursuant to this Section III.13.2.5.2.5~~for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and~~. 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 a Capacity Supply Obligation~~s~~ as described in Section III.13.6.1.

(e~~e~~) 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~~caused the ISO to reject the de-list bid

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~~f) If the reliability need that ~~prevented the de-listing of the resource~~caused the ISO to reject the de-list bid 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).~~ retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

(~~e~~g) If a Permanent De-List Bid or a Retirement De-List Bid ~~that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request~~ is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, 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~~h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list 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~~ De-List Bid or Permanent De-List Bid 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~~De-List Bid~~,~~ ~~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, t~~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, or partial Retirement De-List Bid ~~would otherwise clear in the Forward Capacity Auction but the de-list bid~~ has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or 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. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

~~(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 or a Retirement 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 or III.13.1.2.3.1.5.1 or 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 Commission-approved Permanent D~~d~~e-L~~l~~ist B~~b~~id or Commission-approved Retirement 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 or Retirement 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 Commission-approved Permanent De-List Bid or Commission-approved Retirement 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 or Retirement De-List Bid was submitted. 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 or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b) . Resources that elect payment based on the ~~accepted~~ Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement 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 or Retirement 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.~~

(c~~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~~d) **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, or Retirement 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 Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Resources.~~:~~

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or ~~Non-Price~~ Retirement ~~Request~~ De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section ~~III.13.2.5.2.5.3(a)(iii)~~III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section 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(b~~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 and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: ~~that~~ submitted ~~s~~ a ~~Non-Price~~ Retirement De-List Bid ~~Request~~ that was not included in the Forward Capacity Auction pursuant to Section ~~III.13.1.2.3.1.5~~ III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Internal Market Monitor or Commission-approved Retirement De-List Bid clear~~ed~~ in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1~~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)~~. In~~f~~ the case of a ~~Non-Price~~ Retirement ~~Request~~ De-List Bid Bi~~d~~ rejected for reliability, ~~is approved after the resource has a Capacity Supply Obligation for the Cappacity Commitment Period for which the Non-Price Retirement Request was submitted~~ if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless 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 ~~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) A~~n~~ resource, or portion thereof, ~~Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request~~ that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its ~~Non-Price~~ Retirement ~~Request~~ De-List Bid ~~has been approved~~was submitted 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 no later than 15 days prior to commencement of the relevant Forward Capacity Auction. 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, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: ~~that has~~ submitted a ~~non-partial~~ Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.

III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Internal Market Monitor or Commission-approved Permanent De-List Bid ~~has~~ clear~~ed~~ 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.~~ The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource ~~whose resource~~that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) 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~~-~~.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) ~~with a cleared non-partial Permanent De-List Bid~~ may ~~retire~~ be permanently de-listed ~~the resource~~ earlier than the Capacity Commitment Period for which its Permanent De-List Bid ~~has cleared~~was submitted 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 Retirement De-List Bid, 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 Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, 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 will not be rationed 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.13.2.7.8. [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 and Retirement 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 and Retirement 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 applicable Net CONE value; 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 applicable Net CONE value.

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 import-constrained 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.

(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 the max [applicable Net CONE value, Capacity Clearing Price for the Rest-of-Pool Capacity Zone] 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) [Reserved.]

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

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~~ De-List Bid 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~~ Retirement 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.13.1.1.1.2 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.13.4.2.1.2.1.1.2. 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~~ Retirement 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.13.4.2.1.2.1.1.2(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 where the project has not become commercial.

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 review the net impact of all annual Capacity Supply Obligation Bilaterals to ensure that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are maintained in the Capacity Transferring Resource's Capacity Zone and the Capacity Acquiring Resource's Capacity Zone or across the external interface.

If after its review of the net impact of all annual Capacity Supply Obligation Bilaterals the ISO determines that the regional and local adequacy and other reliability needs achieved through the Forward Capacity Auction are not maintained, and for all monthly Capacity Supply Obligation Bilaterals, the ~~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.

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 ~~Resouce~~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 ~~Resouce~~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

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 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid and Retirement De-List Bid, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has ~~makes~~made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved 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).

(c~~b~~) 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~~ Static De-List Bids, Export Bids, and Administrative De-~~Lits~~List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids ~~de-list bids~~ 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 the Internal Market Monitor establishing an Internal Market Monitor-determined price for 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~~d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(~~a~~c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 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 of the filing that directs otherwise, the determinations contained in the informational filing 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).

~~(c) For the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), the ISO shall make an informational filing with the Commission no later than December 16, 2014 detailing its determination of the New Resource Offer Floor Price for each New Import Capacity Resource making a request and cost information submittal as described in Section III.13.1.3.5.6 and providing supporting documentation for each such determination. These determinations shall be filed confidentially with the Commission in the informational filing. Any comments or challenges to the determinations contained in the informational filing described in this Section III.13.8.1(c) must be filed with the Commission no later than December 23, 2014. If the Commission does not issue an order by January 15, 2015 that directs otherwise, the determinations contained in the informational filing shall be used in conducting the ninth 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 by January 15, 2015, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted 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 Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 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 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.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. 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 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. 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.

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 Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five B~~b~~usiness D~~d~~ays:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five B~~b~~usiness D~~d~~ays of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

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. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, 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 B~~b~~usiness D~~d~~ays following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, 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 must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)

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 B~~b~~usiness D~~d~~ays prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. 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 B~~b~~usiness D~~d~~ays of the applicable Operating Day. The ISO shall correct the error

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

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.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, ~~and~~ Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

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 Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. 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 prices are 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, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices 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(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3 Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

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.

III.A.22 [Reserved.]

III.A.23 Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1 Pivotal Supplier Test

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is

less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2 Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3 ~~Timing of~~ Pivotal Supplier Test ~~and~~ Notification of Results.

~~The pivotal supplier test will be calculated prior to the commencement of the Forward Capacity Auction, and no earlier than the deadline by which a supplier that has submitted a Non-Price Retirement Request for capacity must elect to retire for that auction.~~

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4 Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) 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; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any 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; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24 Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than 105%

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List

Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to~~fails~~ the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor–estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

~~i.~~ The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor–estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v.

vi. The Internal Market Monitor–estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of

the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of December 2, 2015

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 4, 2015 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs (EL15-85)	Nov 10	Settlement Judge Young issues report; settlement judge procedures continue
	2	NEPGA Peak Energy Rent (PER) Complaint (EL15-25)	Nov 19	FERC denies rehearing of Jan 30 order
	4	206 Investigation: FCM PI (Compliance Proceedings) (EL14-52; ER14-2419)	Nov 19	FERC denies rehearing of both its May 30, 2014 *PI Order* on the FCM PI Jump Ball Filing and its *October 2 Order* on the first Compliance filing in response to the *PI Order*
	5	206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices Adopted in *Order 809* (EL14-23)	Nov 19	FERC accepts ISO-NE compliance filing

II. Rate, ICR, FCA, Cost Recovery Filings

*	6	ICR-Related Values and HQICCs - 2016/17 ARA3, 2017/18 ARA2, 2018/19 ARA1 (ER16-446)	Dec 1	ISO and NEPOOL jointly file ICR-Related Values and HQICCs for the 2016/17 ARA3, 2017/18 ARA2; and 2018/19 ARA1; comment date Dec 22
*	7	FCA10 Qualification Informational Filing (ER16-308)	Nov 10 Nov 12-25 Nov 25	ISO submits required informational filing for FCA10; NEPOOL, Dominion, Entergy, Eversource, Exelon, NESCOE, NRG, UI intervene Lotus Energy Group files limited protest
*	7	ICR, HQICCs and Related Values - 2019/20 Power Year (ER16-307)	Nov 10 Nov 12-Dec 1 Dec 1	ISO files ICR, HQICCs, and related values for the 2019/20 Capability Year; comment date Dec 1 Emera, Entergy, Eversource, Exelon, GDF Suez, National Grid intervene NEPOOL, NESCOE file comments; NEPGA, NRG, Dominion file protests
	8	2016 NESCOE Budget (ER16-93)	Nov 6	Eversource intervenes
	8	2016 ISO-NE Administrative Costs and Capital Budgets (ER16-92)	Nov 6	Eversource intervenes

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

	10	NCPC Credit Revisions (ER16-250)	Nov 12-23	Dominion, Entergy, Eversource, Exelon, National Grid intervene

	10	CSO Terminations: GMP (ER16-226) Enerwise (ER16-225) Direct Energy (ER16-224) Twin Eagle (ER16-223) Brookfield White Pine Hydro (ER16-222)	Nov 13	NEPOOL intervenes in each of the proceedings
	11	DR Changes (ER16-167)	Nov 3-19	NRG, NESCOE, ConEd, Dominion, Emera, Entergy, Eversource, Exelon, National Grid intervene
	11	Reactive Capability Auditing Revisions (ER15-2628)	Nov 12	FERC accepts changes, eff. Dec 1
	11	Jump Ball Filing: Winter Reliability Program (ER15-2208)	Nov 6 Nov 9 Nov 16	NEPOOL supports the ISO's Oct 26 compliance filing FERC issues tolling order affording it additional time to consider Entergy request for rehearing of Sep 11 order NEPOOL, NEPGA file comments supporting the ISO's Oct 26 filing
	13	Jump Ball Filing: FCM Performance Incentives (ER14-1050)	Nov 19	FERC denies rehearing, and dismisses as moot requests for clarification, of *PI Order*
	13	Capability Resource Ratings Rehearing Request (ER11-2216)	Nov 12	FERC denies MMWEC Feb 2011 rehearing request

IV. OATT Amendments / TOAs / Coordination Agreements

	13	Retirement of RTO Mapping Document (Tariff Attachment C) (ER15-2717)	Nov 17	FERC accepts retirement of RTO Mapping Document
	13	CTS Conforming Changes (ER15-2641)	Nov 9 Dec 1	FERC conditionally accepts changes, eff. Dec. 1, 2015 (subject to 2 weeks' prior notice), and subject to corrections to be filed with effective date notice ISO files notice of Dec 15, 2015 effective date and minor corrections directed by Nov 9 order
	14	*Order 1000* Interregional Compliance Filings (ER13-1960; ER13-1957)	Nov 19	FERC accepts Second (and final) *Order 1000* Interregional Compliance Filing
	14	*Order 1000* Regional Compliance Filings (ER13-193; ER13-196)	Nov 23	NEPOOL files comments supporting 4th Regional Compliance Filing (filed Nov 2)

V. Financial Assurance/Billing Policy Amendments

*	15	Estimation of Hourly Charges (ER16-286)	Nov 6 Nov 12-23	ISO and NEPOOL jointly file changes National Grid, Eversource intervene

VI. Schedule 20/21/22/23 Changes

*	15	Schedules 20A-ES & 21-ES: Eversource Updates (ER16-348)	Nov 18	Eversource files to change title of Schedules 20A-NU and 21-NU to Schedule 20A-ES and 21-ES, respectively, and to replace all references to NU and Northeast Utilities to ES and Eversource
*	16	Schedule 21-EM: Corrections (ER16-273)	Nov 6	Emera Maine files corrections to Schedule 21-EM
	16	Schedule 22: Granite Ridge LGIA (ER15-2747)	Nov 13	FERC accepts Granite Ridge LGIA

VII. NEPOOL Agreement/Participants Agreement Amendments

	16	128th Agreement: GIS-Only Participant Status (ER16-214)	Nov 12	National Grid intervenes

	16	129th Agreement: Review Board Removal (ER16-159)	Nov 12,19	National Grid, Eversource intervene

VIII. Regional Reports

	17	Capital Projects Report - 2015 Q3 (ER16-94)	Nov 6 Nov 24	Eversource intervenes FERC accepts the Q3 Report
*	17	ISO-NE FERC Form 3Q (2015/Q3) (not docketed)	Nov 17	ISO submits quarterly financial report for 2015 Q3

IX. Membership Filings

*	17	December 2015 Membership Filing (ER16-428)	Nov 30	Memberships: Niagara Wind Power, Residents Energy, Utility Expense Reduction; Terminations: Barclays and Twin Cities Power; comment date Dec 20
	18	October 2015 Membership Filing (ER16-1)	Nov 13	FERC accepts the memberships of: Antrim Wind Energy, Astral Energy, Beacon Falls Energy Park, Champlain VT, Concord Steam, Deepwater Wind Block Island, Invenergy Energy Management, MA Operating Holdings; the terminations of: HOP Energy, energy.me, Parkview AMC Energy, Denver Energy, Johnston Clean Power; and the name change of NRG Curtailment Solutions, Inc.

X. Misc. - ERO Rules, Filings; Reliability Standards

	18	FFT Report: November 2015 (NP16-3)	Nov 30	NERC files report
	18	Revised Reliability Standards: PRC-004-5; PRC-010-2 (RD15-5)	Nov 19	FERC approves Standards, eff. Nov 19
	18	*Order 817*: Revised TOP and IRO Reliability Standards (RM15-16)	Nov 19	FERC approves Revised Standards, eff. Jan 26, 2016
	19	*Order 818*: Revised Reliability Standards: Transition to "Remedial Action Scheme" (RM15-13)	Nov 19	FERC approves Revised Standards, eff. Jan 26, 2016
	20	NOPR: New Reliability Standard: TPL-007-1 (RM15-11)	Nov 9-24	US Geological Survey, Southern Company, IEEE, SAC & AFS, J. Bardin submit reply comments
	20	NOPR: New Reliability Standard: PRC-026-1 (RM15-8)	Nov 16-24	NERC, Luminant, EEI, Idaho Power, ITC, N. Amer. Generator Forum, and the Tri-State Generation and Transmission Assoc.
	22	E. Morris v. NERC/SERC (EL15-93)	Dec 2	FERC dismisses complaint and petition for rulemaking

XI. Misc. - of Regional Interest

	23	203 Application: Passadumkeag Wind Park (SunEdison/Quantum) (EC15-217)	Nov 17	FERC approves SunEdison acquisition of membership interests in Passadumkeag Wind Park
*	23	PURPA Complaint: Allco Renewable Energy v. CT Agencies (EL16-11 et al.)	Nov 9 Nov 19-23 Nov 30 Dec 2	Allco files petition for FERC enforcement of PURPA against CT Agencies Eversource, Exelon, National Grid, UI intervene CT Agencies protest complaint CT Agencies file notice of amended Federal Court decision in a case relied upon by Allco

*	24	LGIA – PSNH/Schiller Generating Station (ER16-391)	Nov 25	Eversource files two-party LGIA with Schiller Generating Station (a previously existing interconnection) to demonstrate compliance with REC Purchase Agreements; comment date Dec 16
*	24	PSNH/NHEC Design & Engineering Agreement Cancellation (ER16-357)	Nov 19	Eversource files cancellation notice for Agreement; comment date Dec 10
*	24	CPV Towantic EDPS Agreement Cancellation (ER16-356)	Nov 19	Eversource files cancellation notice for EDPS Agreement; comment date Dec 10
*	24	Wyman 4 Transmission Agreement (ER16-272)	Nov 5	CMP supplements Wyman 4 Transmission Agreement to (i) revise definition of Transmission Facilities; (ii) update identities of owners; and (iii) clarify references to ISO Tariff
*	27	FERC Audit of ISO-NE	Nov 24	FERC informs ISO-NE that it will conduct an audit of ISO-NE's Transmission Provider Obligations

XII. Misc. - Administrative & Rulemaking Proceedings

*	27	Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)	Nov 20	FERC directs RTO/ISOs (including ISO-NE) to provide information regarding 5 price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency; RTO/ISO response date Feb 3, 2016
	27	Enforcement Annual Report (AD07-13-009)	Nov 19	FERC Office of Enforcement issues 2015 Annual Report
*	27	NOPR: Reactive Power Requirements for Wind Generators (RM16-1)	Nov 19	FERC proposes to eliminate the exemptions for wind generators from the requirement to provide reactive power by changing the *pro forma* LGIA and SGIA; comment date Jan 25, 2016
	28	NOPR: Price Formation Fixes - Settlement Intervals/Shortage Pricing (RM15-24)	Nov 30	Nearly 50 sets of comments were filed, including comments by NEPOOL, ISO-NE, Potomac Economics, APPA/NRECA, EEI, EPSA, Direct Energy, Dominion, Entergy, ESA, Exelon, IRC, NEI, Public Interest Organizations, PSEG
	28	NOPR: Connected Entity Data Collection (RM15-23)	Nov 10	FERC grants request for technical conference (scheduled for Dec 8) and delay in comment submission (to Jan 22, 2016)
			Nov 30	FERC issues supplemental notice Dec 8 technical conference; Public Citizen files comments
			Dec 1	NEPOOL files comments
	29	*Order 812*: Revisions to Public Utility Filing Requirements (RM15-3)	Nov 19	FERC grants clarification of *Order 812* requested by Dominion
	29	*Order 819*: Third-Party Provision of Primary Frequency Response Service (RM15-2)	Nov 20	FERC issues *Order 819*, eff. Feb 25, 2016
	30	*Order 816*: MBR Authorization Refinements (RM14-14)	Nov 13-16	EDF Renewables, EEI, EPSA, Invenergy, NextEra, Southern Company, TAPS, SoCal Edison, National Hydropower Assoc. file requests for clarification and/or rehearing of *Order 816*

XIII. Natural Gas Proceedings

	34	*Opinion No. 538*: ANR Storage Company, Order on Initial Decision (RP12-479)	Nov 13-16	ANR and Joint Intervenor Group request rehearing of *Opinion No. 538*

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

37	Base ROE Complaints (2012 and 2014) (15-1212)	Nov 18	Parties file 1st 90-day status report
37	*Order 1000* Compliance Filings (15-1139, 15-1141**) (consolidated)	Nov 6	Court issues order setting briefing schedule
37	Base ROE Complaint (2011) (15-1118, 15-1119, 15-1121**) (consolidated)	Dec 2	FERC files Supplement to the Certified Index of the Record
38	FCM Administrative Pricing Rules Complaint (15-1071**)	Nov 18	NEPGA files status report requesting Court continue to hold this case in abeyance
38	Demand Curve Changes (15-1070**)	Nov 20	FERC requests that the Court remand this case back to the Commission for further proceedings
		Dec 1	Court grants FERC's unopposed motion
39	FCA8 Results (14-1244, 14-1246 (consolidated))	Nov 18	EPSA/HQ US/NRG/NEPGA file Intervenor for Respondent Brief; Calpine files letter advising that it will not file a brief
		Dec 2	CT OCC/CT PURA/CT AG and Public Citizen file Petitioner Reply Briefs

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: December 2, 2015

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 2, 2015. If you have questions, please contact us.[1]

I. Complaints/Section 206 Proceedings

- **206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs (EL15-85)**

On August 12, 2015, the FERC issued an order accepting the TOs' July 31, 2014 informational rate filing but, in response to a protest by "Public Representatives",[2] instituted a Section 206 proceeding in Docket EL15-85 to examine whether the recovery by New Hampshire Transmission ("NHT") of SeaLink project development costs through the RNS formula rate is just and reasonable.[3] The FERC encouraged the parties to make every effort to settle their dispute before hearings are commenced, and will hold the hearings in abeyance pending the outcome of settlement judge procedures.[4] Interventions were filed by ISO-NE, NEPOOL, CMP, CT OCC, CT PURA, Eversource, MA AG, MOPA, National Grid, NESCOE, RI PUC, UI, VT DPS, and VT Transco. The FERC-established refund effective date is August 19, 2015.[5]

Settlement Judge Proceedings. On August 19, Chief Judge Wager appointed Judge H. Peter Young as the Settlement Judge. A first settlement conference was held on September 15; a second settlement conference, October 29, 2015. On November 10, Judge Young issued a report stating "Substantive going-forward settlement principles seem to be reconcilable among the participants, but there remains a potentially unbridgeable gulf between them insofar as total going-forward financial responsibility is concerned." For now, settlement judge procedures are continuing. If there are questions on these proceedings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[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. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] "Public Representatives" are the MA AG, CT OCC, CT PURA, the RI PUC, the Attorney General of the State of Rhode Island ("RI AG"), the Maine Public Advocate ("MOPA") and the Vermont Department of Public Service ("VT DPS").

[3] *ISO New England Inc. Participating Transmission Owners Administrative Committee and New Hampshire Transmission, LLC*, 152 FERC ¶ 61,121 (Aug. 12, 2015).

[4] *Id.* at P 20.

[5] The notice of this proceeding was published in the *Fed. Reg.* on Aug. 19, 2015 (Vol. 80, No. 160) p. 50,271.

- **NEPGA Peak Energy Rent (PER) Complaint (EL15-25)**

On November 19, the FERC denied NEPGA's and Entergy's requests for rehearing[6] of the FERC's January 30 order[7] denying NEPGA's PER Complaint. As previously reported, the *PER Complaint Order* found that NEPGA had failed to meet its burden under Section 206 of the Federal Power Act to demonstrate that the existing ISO Tariff provisions were unjust and unreasonable.[8] On March 2, NEPGA and Entergy challenged the *PER Complaint Order*. NEPGA argued the FERC should "reverse its finding … that NEPGA did not satisfy its Section 206 burden in the Complaint with respect to the relief sought for Capacity Commitment Periods 5 through 8" and "clarify that the [FERC], not the complainant, carries the burden under Section 206 of establishing a just and reasonable "replacement" rate". If rehearing is denied, NEPGA asked the FERC to clarify that it "did not intend to prejudge any future proceeding on the PER Adjustment issue by establishing a required evidentiary standard" in the *PER Complaint Order*. In its request, Entergy, adopting and incorporating NEPGA's request, provided additional bases to support its request for rehearing of the *PER Complaint Order*. Entergy challenged further the FERC's reliance on (i) the ISO's assessment of the PER adjustment's reliability impacts and, with respect to Capacity Commitment Periods 5-8, (ii) the stakeholder process considering changes to the PER rules. In the November 19 rehearing order, the FERC denied rehearing as to all issues raised by NEPGA and Entergy.[9] Unless further challenged in the Federal Courts, this matter will be concluded. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **New Entry Pricing Rule Complaint (EL15-23)**

Exelon and Calpine's request for rehearing of the FERC's January 30 order denying the New Entry Pricing Rule Complaint[10] remains pending. As previously reported, the *New Entry Pricing Rule Complaint Order* found that Exelon and Calpine had failed to show that the existing pricing rules governing lock-in capacity result in unjust, unreasonable or unduly discriminatory price suppression. In their rehearing request, Exelon and Calpine assert, among other things, that the *New Entry Pricing Rule Complaint Order* (i) did not provide a reasoned basis for finding that there is no artificial price suppression in post-entry FCAs; (ii) did not address Exelon/Calpine's arguments regarding artificial price suppression in the entry FCA; and (iii) ignored arguments regarding the undue discrimination that results from the current Market Rules. On April 1, 2015, the FERC issued a tolling order affording it additional time to consider Exelon's and Calpine's rehearing request, which remains 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).

- **NEPGA DR Capacity Complaint (EL15-21)**

NEPGA's November 14, 2014 complaint remains pending before the FERC. As previously reported, the complaint requests that (i) Demand Response ("DR") Capacity Resources be disqualified from FCA9 and

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[6] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 153 FERC ¶ 61,222 (Nov. 19, 2015) ("*PER Complaint Rehearing Order*").

[7] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 150 FERC ¶ 61,053 (Jan. 30, 2015) ("*PER Complaint Order*"), *reh'g denied*, 153 FERC ¶ 61,222 (Nov. 19, 2015).

[8] NEPGA's Dec. 3, 2014 complaint requested that the ISO be directed (i) to increase the daily PER Strike Price by $250/MWh for Capacity Commitment Periods 5 through 8, and (ii) to eliminate the PER Adjustment for FCA9 and beyond, or, alternatively, to continue the $250 per MWh increase in the PER Strike Price for FCA9. The changes proposed in the Complaint were considered but not supported by the Participants Committee at its Oct. 3, 2014 meeting.

[9] *PER Complaint Rehearing Order* at P 20.

[10] The FERC stated that much of the complainants' argument rested on the assertion that ISO-NE's lock-in resource requirements differ from PJM's. The FERC acknowledged that ISO-NE's and PJM's differing mechanics may yield different prices paid to existing resources, but the FERC was not persuaded that the difference itself renders ISO-NE's rules unjust and unreasonable. *Exelon Corp. and Calpine Corp. v. ISO New England Inc.*, 150 FERC ¶ 61,067 at P 35 (Jan. 30, 2015) ("*New Entry Pricing Rule Complaint Order*"), *reh'g requested*.

(ii) the Tariff be revised to exclude DR from FCM participation going forward (as a result of *EPSA v. FERC*). Interventions were filed by AEP, Brookfield, Calpine, ConEd, CSG, Direct, Dominion, EEI, ELCON, Emera, EnergyConnect, EnerNOC, Entergy, Exelon, FirstEnergy, Maryland Public Service Commission ("MD PSC"), NextEra, NRG, PPL, and Wal-Mart stores. NEPOOL filed comments on November 26 asking the FERC to reject the NEPGA Complaint without prejudice to a complaint being resubmitted if and as appropriate following consideration of specifically-proposed changes to the Tariff within the Participant Processes. Eversource and UI jointly protested the complaint on December 3, requesting that the FERC either dismiss or hold the Complaint in abeyance. The ISO answered the Complaint on December 4. Also on December 4, Advanced Energy Management Alliance, NESCOE, Conn/RI,[11] Enerwise, Environmental Advocates,[12] NGrid, Public Systems, and the Sustainable FERC Project opposed the Complaint; EPSA and PSEG supported the Complaint; Genbright submitted comments. On December 15, CT PURA moved to lodge the December 15 DC Circuit Court order extending the stay of the mandate in *EPSA v. FERC*. On December 19, NEPGA answered the ISO response and the other pleadings submitted in response to its Complaint. On January 7, just as they had on December 23 in the FirstEnergy Complaint (*see* Section XI below), Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. As noted, this matter remains pending before the FERC. If you have any questions concerning these matters, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaints (2012 and 2014) Consolidated (EL13-33 and EL14-86)**

As previously reported, the FERC, in response to second (EL13-33[13]) and third (EL14-86[14]) complaints regarding the TOs' 11.14% return on equity ("Base ROE"), issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;[15] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[16] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund

[11] "Conn/RI" is the Connecticut Public Utilities Regulatory Authority ("CT PURA"), George Jepsen, Att'y Gen. for the State of Conn. ("CT AG"), the Conn. Department of Energy and Environmental Protection ("CT DEEP"), the Conn. Office of Consumer Counsel ("CT OCC"), and the Rhode Island Div. of Public Utilities and Carriers ("RI PUC").

[12] "Environmental Advocates" are the Sustainable FERC Project, Sierra Club, Environmental Defense Fund, and Acadia Center.

[13] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[14] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[15] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co.*, et al., 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

[16] *Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

period."[17] The TOs requested rehearing of both orders. On May 14, the FERC denied rehearing of both orders.[18] On July 13, the TOs appealed those order to the D Circuit Court of Appeals (see Section XIV below).

Hearings. The hearings in this mater began June 25, 2015 and were completed on July 2. Just prior to the commencement of the hearing, pursuant to an unopposed motion of the TOs, Judge Sterner adopted a proposed protective order to permit the exchange and use during hearing of certain confidential materials provided by Thomson Reuters. Joint Transcript Corrections and a Final Index of Exhibits were submitted on July 13, 2015. Judge Sterner adopted the transcript corrections on July 15. On July 23, the TOs filed a motion to lodge portion of testimony filed in the Southwestern Public Service Co. ROE proceeding (EL15-8) to show inconsistent positions of FERC Trial Staff. That motion to lodge was opposed by Complainant-Aligned Parties, EMCOS, and FERC Trial Staff on August 7 and denied by Trial Judge Sterner on August 13. On July 29, 2015, a Joint Procedural History was submitted, as were initial briefs by the Complainant-Aligned Parties, TOs, EMCOS and FERC Staff. On August 26, 2015, Reply Briefs were submitted by the Complainant-Aligned Parties, TOs, EMCOS and FERC Staff , as was a Joint List of Appearances. With all briefing completed, the parties await Judge Sterner's initial decision, which is to be issued by December 30, 2015. 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).

- **206 Investigation: FCM Performance Incentives (Compliance Proceedings) (EL14-52; ER14-2419)**

On November 19, the FERC denied rehearing of both its May 30, 2014 *PI Order*[19] on the FCM PI Jump Ball Filing and its *October 2 Order*[20] on the first Compliance filing in response to the *PI Order*.[21] As previously reported, the FERC instituted this proceeding, pursuant to Section 206 of the FPA, in its May 30 *PI Order* on the FCM Performance Incentives Jump Ball filing. In the *PI Order*, the FERC concluded that the ISO's FCM payment design was "unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits."[22] The FERC directed the ISO to submit "Tariff revisions reflecting a modified version of its [PFP] proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's proposal."[23] The FERC-established refund effective date was June 9, 2014.[24] Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL,

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[17] *Id.* at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

[18] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 151 FERC ¶ 61,125 (May 14, 2015).

[19] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014) ("*PI Order*"), *clarif. and reh'g requested*.

[20] *ISO New England Inc.*, 149 FERC ¶ 61,009 (Oct. 2, 2014) ("*October 2 Order*"), *reh'g requested*.

[21] *ISO New England Inc. and New England Power Pool*, 153 FERC ¶ 61,223 (Nov. 19, 2015) (denying rehearing of the *PI Order*); *ISO New England Inc.*, 153 FERC ¶ 61,224 (Nov. 19, 2015) (denying rehearing of the *October 2 Order*) (together, the "*November 19 Orders*").

[22] *PI Order* at P 23.

[23] *Id.* at P 1.

[24] The June 3 notice of this proceeding was published in the *Fed. Reg.* on June 9, 2014 (Vol. 79, No. 110) pp. 32,937-89.

Connecticut and Rhode Island,[25] Dominion, MMWEC, Indicated Generators,[26] NEPGA, NextEra, Potomac Economics, and PSEG/NRG.

In its *October 2 Order*, the FERC accepted in part, subject to condition, and rejected in part, the ISO's July 14, 2014 Compliance filing ("Compliance Filing I") that, as previously reported, had been filed in response to directives in the *PI Order*. While accepting nearly all of the provisions proposed in Compliance Filing I, the *October 2 Order* rejected the ISO's Compliance proposal concerning improper price signals caused by binding intra-zonal transmission constraints.[27] Tariff sections removing that aspect of the ISO's July 14 Compliance proposal and restoring language originally proposed by the ISO in its January 17 Filing, were filed and accepted effective June 9, 2014, December 3, 2014, and June 1, 2018, as requested.[28] Connecticut/Rhode Island[29] and Public Systems[30] requested rehearing of the *October 2 Order* on November 3, 2014.

In the *November 19 Orders*, the FERC rejected all of the requests for rehearing and/or clarification filed in response to the *PI Order* and *October 2 Order*. Unless further challenged in the Federal Courts, this proceeding has been concluded. If you have any questions related to these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices Adopted in *Order 809* (EL14-23)**

On November 19, the FERC accepted the ISO's compliance in this proceeding.[31] As previously reported, the FERC initiated this proceeding on March 20, 2014, pursuant to Section 206 of the FPA, to ensure that the ISO's scheduling, particularly its Day-Ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices to be ultimately adopted by the FERC in *Order 809* (*see* Section XIII below).[32] Noting its concern about the lack of synchronization between the Day-Ahead scheduling practices of interstate natural gas pipelines and electricity markets, the FERC directed each ISO and RTO, including ISO-NE, within 90 days after publication of Order 809 (or, as discussed in Section XIII below, Thursday, July 23, 2015)*:*

> (1) to make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or (2) to show cause why such changes are not necessary. In their responses, each ISO and RTO must explain how its

[25] "Connecticut and Rhode Island" are: the CT PURA, CT OCC, CT AG, CT DEEP, the United Illuminating Company ("UI") and the RI PUC.

[26] "Indicated Generators" are: Exelon Corp. ("Exelon"), EquiPower Resources Management, LLC ("EquiPower"), Essential Power, LLC ("Essential Power"), and Dynegy Marketing and Trade, LLC and Casco Bay Energy Company, LLC (together, "Dynegy").

[27] *October 2 Order* at P 56.

[28] *October 2 Order* at P 1; Ordering Paragraph (A).

[29] "Connecticut/Rhode Island" are the CT PURA, CT AG, CT OCC, CT DEEP, and the RI PUC.

[30] "Public Systems" are CMEEC, MMWEC, NHEC, and VEC.

[31] *ISO New England Inc.*, 153 FERC ¶ 61,211 (Nov. 19, 2015) at P 2.

[32] *Cal. Indep. Sys. Op. Corp. et al.*, 146 FERC ¶ 61,202 (Mar. 20, 2014). The New England 206 proceeding was docketed as EL14-23.

proposed scheduling modifications are sufficient for gas-fired generators to secure natural gas pipeline capacity prior to the Timely and Evening Nomination Cycles.[33]

ISO Response to Show Cause Order. On July 23, 2015, the ISO filed its response. In that filing, the ISO described why changes to the time at which the results of the Day-Ahead Energy Market and RAA process are posted were not necessary in response to *Order 809*. In its November 19 order, the FERC found that the ISO had "shown cause why its existing scheduling practices need not be changed and [accepted] ISO-NE's compliance filing."[34] In response to concerns raised by NRG, the FERC "recognize[d] the benefits that could accrue from faster solve times and encourage[d] ISO-NE to continue work with its stakeholders, in an effort to improve market efficiency, to develop means to reduce its solve time further and allow market participants to submit bids reflecting increased fuel price certainty."[35] Unless the November 19 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint (2011) Refund Reports (EL11-66)**

On November 2, the TOs submitted a refund report documenting resettlements of regional transmission charges by the ISO in compliance with *Opinions No. 531-A*[36] *and 531-B.*[37] As previously reported, following the issuance of *Opinion 531-B*, which denied rehearing of *Opinion 531*[38] and *Opinion 531-A*, the TOs requested an extension of time to permit the following deadlines in connection with refunds resulting from *Opinion No. 531-B*: August 31, 2015, for regional refunds; October 31, 2015, for the regional refund report; October 31, 2015, for local refunds; and December 31, 2015, for the final local refund report. The TOs state that they intend to submit additional local refund reports by December 31, 2015. Other than the filing of the local refund reports, and absent a successful challenge in the federal courts (see Section XV below), these proceedings are concluded. 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

- **ICR-Related Values and HQICCs - 2016/17 ARA3, 2017/18 ARA2, 2018/19 ARA1 (ER16-446)**

On December 1, 2015, 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 System-Wide Demand Curve for the third annual reconfiguration auction ("ARA") for the 2016/17 Capability Year to be held March 1, 2016, the second ARA for the 2017/18 Capability Year to be held August 1, 2016, and the first ARA for the 2018/19 Capability Year to be held June 1, 2016. The ICR-Related Values and HQICCs were supported by the Participants Committee at its November 6, 2015 meeting. A January 30, 2016 effective date was requested. Comments on this filing are due December 22, 2015. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[33] *Id.* at P 19.

[34] *ISO New England Inc.*, 153 FERC ¶ 61,211 (Nov. 19, 2015) at P 2.

[35] *Id.* at P 21.

[36] *Martha Coakley, Mass. Att'y Gen. et al.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[37] *Martha Coakley, Mass. Att'y Gen. et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[38] *Martha Coakley, Mass. Att'y Gen. et al.*, 147 FERC ¶ 61,234 (June 19, 2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014), *reh'g denied*, 150 FERC ¶ 61,165 (Mar. 3, 2015).

- **FCA10 Qualification Informational Filing (ER16-308)**

On November 10, 2015, the ISO submitted its informational filing (the "FCA10 Informational Filing") for qualification in FCA10. 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. FCA10 is scheduled to begin February 8, 2016. The Informational Filing contained the ISO's determinations that two Capacity Zones, Southeastern New England ("SENE") and Rest of Pool, will be modeled for FCA10. SENE will be modeled as import-constrained Capacity Zones; no export-constrained Capacity Zones will be modeled (and, accordingly, no Maximum Capacity Limits ("MCLs") were established). The Informational Filing reported that there will be 33,411 MW of existing capacity in FCA9 competing with 6,720 MW of new capacity under a procurement limit of 34,151 MW (ICR minus HQICCs). The ISO reported also that there were a total of 1,382 MW of Static De-list bids, 97 MW of which were later converted into Non-Price Retirement Requests. A summary of the De-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E.

Comments on the FCA10 Informational Filing were due November 25, 2015. Lotus Energy Group submitted a limited protest, requesting that the ISO be directed to revise the New Resource Offer Floor Price for its projects, by reflecting what it asserts is the correct cost of equity for the projects. No other comments or protests were filed. Interventions were filed by NEPOOL, Dominion, Entergy, Eversource, Exelon, NESCOE, NRG, and UI. 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).

- **ICR-Related Values and HQICCs - 2019/20 Power Year (ER16-307)**

Also on November 10, 2015, the ISO filed ICRs, Hydro Quebec Interconnection Capability Credits ("HQICCs") and related Local Sourcing Requirements ("LSR") values for the 2019/2020 Capability Year. The values will be used in FCA10 to be held in February 2016. With a 2019/20 ICR of 35,151 MW (reflecting tie benefits of 1,990 MW) and HQICCs of 975 MW/mo., the net amount of capacity to be purchased in FCA9 to meet the ICR will be 34,151 MW. The LSR for the SENE Capacity Zone is 10,028. The 1-in-5 Loss of Load Expectation ("LOLE") and 1-in-87 LOLE capacity requirement values for the Demand Curve are 33,076 MW and 37,053 MW, respectively. The Participants Committee considered, but did not support the ICR, HQICCs and related values at its October 2, 2015 meeting. Comments on this filing were due December 1 and were filed by NEPOOL and NESCOE. Protests were filed by NEPGA, Dominion, and NRG (each addressing the incorporation of the load forecast for behind-the-meter photovoltaic resources and other technologies). Interventions were filed by Emera, Entergy, Eversource, Exelon, GDF Suez, and National Grid. 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).

- **Eversource CCRP Cost Treatment Proposal (ER16-116)**

On October 19, Eversource submitted a proposal, including changes to OATT Attachment F and the Attachment F Implementation Rule, to treat $15.7 million incurred in connection with the Central Connecticut Reliability Project ("CCRP") as capital costs of the New England East-West Solution ("NEEWS") transmission project. As part of its proposal, Eversource proposes to forgo the two ROE incentive adders that the FERC granted to the NEEWS Project (i.e., the 125 basis points for new transmission under *Order 679* and 50 basis points for participation in an RTO), given this component was redesigned and subsumed into a successor transmission project that does not have transmission incentives under *Order 679*. Eversource requested an April 16, 2015 effective date (the date on which ISO-NE approved the Greater Hartford and Central Connecticut Project and Eversource withdrew its original CCRP PPAs from consideration in the RSP. Eversource states that its proposal will have a rate reduction effect. Comments on this filing are due on or before November 9, 2015. Thus far, doc-less interventions have been filed by NESCOE, MA AG, and National Grid. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **2016 NESCOE Budget (ER16-93)**

This proceeding was initiated by the ISO's October 16 filing of the budget for funding NESCOE's 2016 operations. The 2016 Operating Expense Budget for NESCOE is $2,200,259. The amount to be recovered reflects true-ups for actual costs and collections in prior years that cumulatively amount to approximately $1.5 million. Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00296 per kilowatt of Monthly Network Load. The 2016 NESCOE budget was supported by the Participants Committee at its October 2, 2015 meeting. On November 4, NEPOOL filed comments supporting the filing. All other comments and any interventions were due on or before November 6; no others were filed. Eversource filed a doc-less motion to intervene. This matter remains pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2016 ISO-NE Administrative Costs and Capital Budgets (ER16-92)**

Also on October 16, the ISO filed for recovery of its 2016 administrative costs (the "2016 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 201 ("2016 Capital Budget", and together with the 2016 Revenue Requirement, the "2016 ISO Budgets"). The 2016 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO Budgets. In the October 16 filing, the ISO reported that the 2016 Revenue Requirement (allowing the ISO to maintain the status quo and to fund established initiatives), after true-up for 2014, is $184.5 million. Of that total, the ISO's administrative costs (i.e., the 2015 Core Operating Budget) comprise $152.2 million; depreciation and amortization of regulatory assets, $33 million; and 2014 true-up, $600,000.

The ISO further reported that the 2016 Capital Budget is $27 million and is comprised of the following (with 2016 projected costs and target completion dates, if available, in parentheses):

‣ Wind Integration Phase II / Do Not Exceed Dispatch (May 2016)	($2.47 million)	‣ Asset Characteristics Database & User Interface Redesign (Q3 2016)	($700,000)
‣ FCA10 (May 2016)	($590,000)	‣ Energy Management Platform Customs Elimination (Q4 2017)	($600,000)
‣ Divisional Accounting (2016)	($496,800)	‣ Operations Document Management System ("ODMS") (Q4 2016)	($600,000)
‣ Zonal Load Forecast (Mar 2016)	($225,000)	‣ Transmart Rewrite (Q4 2016)	($500,000)
‣ Power System Modelling Management (Aug 2017)	($145,000)	‣ Web Enhancements (2016)	($500,000)
‣ NX9/NX12D – Generator Voltage Data (Feb 2016)	($50,000)	‣ Asset Registration Automation (Q4 2016)	($500,000)
‣ FCA11 (Feb 2017)	($3 million)	‣ Dynamic Interface Adjustment Tool (Q4 2016)	($300,000)
‣ Sub-Hourly Settlements (Q4 2016)	($2.5 million)	‣ Oracle 12c Upgrade (Q2 2016)	($100,000)
‣ Fast-Start Pricing (Q1 2017)	($2.5 million)	‣ Case Snapshot Enhancements for Market Operator Interface PRD (Q4 2016)	($100,000)
‣ Submission of FTR for Clearing (Q4 2016)	($1.8 million)	‣ Price Responsive Demand (Q3 2018)	($100,000)
‣ 2016 Issues Resolution Project (Q4 2016)	($1.5 million)	‣ Non-Project Capital Expenditures	($3.7 million)
‣ Expand Energy Offers for Pumps (Q4 2016)	$900,000	‣ Other Emerging Work	($1.81 million)

- Quarterly Release Projects 2016 (Quarterly) ($800,000)
- Capitalized Interest ($500,000)

The 2016 ISO Budgets were supported by the Participants Committee at its October 2, 2015 meeting. Doc-less interventions were filed by NEPOOL, NESCOE, CT PURA, Eversource, and National Grid. NEPOOL filed comments on November 5 supporting the filing. This matter remains pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) Jennifer Galiette (860-275-0338; jgaliette@daypitney.com).

- **FCA9 Results Filing (ER15-1137)**

Rehearing of the FERC's June 18, 2015 order accepting the results of FCA9, effective June 27, 2015,[39] remains pending. As previously reported, the Utility Workers Union of America Local 464 and Robert Clark ("UWUA") requested rehearing of the *FCA9 Results Order* on July 20, 2015. On August 19, 2015, the FERC issued a tolling order affording it additional time to consider the UWUA request for clarification, which, as noted above, remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order[40] that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding[41] for further consideration. In particular, the FERC was directed to (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 June 2, 2015, in a long-awaited order, the FERC reversed its prior determination and found that, given that the ISO had prohibited resources needed for reliability from prorating quantity based on its interpretation of the Proration Rule, it was appropriate to consider resettlements to those resources that were not able to prorate quantity.[42] "[W]here resources needed for reliability were prohibited from prorating quantity under the Proration Rule, they should have received the full market clearing price for each megawatt offered."[43] Although the FERC found that the ISO reasonably interpreted the Proration Rule as allowing it to limit certain suppliers' ability to prorate quantity, in order to maintain reliability, and the FERC disagrees with PSEG's argument that it would be unduly discriminatory under the FPA to make unavailable to certain resources the option to choose quantity proration instead of price proration, the FERC found that resources prevented from prorating quantity must also receive "a just, reasonable, and not unduly discriminatory or preferential rate," (i.e. the full clearing price for each megawatt offered).

Accordingly, the FERC established a briefing schedule to permit the parties to address issues relating to the amounts of such resettlements (i.e., the difference between a resource's actual payment and what the payment would have been had proration of the resource not been rejected for reliability reasons), and the parties to which those payments should be charged and to whom they should be paid (taking into

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[39] *ISO New England Inc.*, 151 FERC ¶ 61,226 (June 18, 2015) ("*FCA9 Results Filing*").

[40] *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[41] *ISO New England Inc.*, 123 FERC ¶ 61,290 (2008); *reh'g denied*, 130 FERC ¶ 61,235 (2010), *remanded*, PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[42] *ISO New England Inc.*, 151 FERC ¶ 61,196 (June 2, 2015) ("*FCA1 Remand Order*").

[43] *Id.* at P 14.

consideration any possible changes in ownership, retirements, or similar new circumstances of the resources in question).

In its initial brief filed on July 17, the ISO identified:

- the Connecticut resources that were unable to prorate quantity in FCA1, and the number of MWs for which each resource received a CSO;
- the resettlements due to each such entity, based on the difference between (1) the prorated price that the resources did receive (4.254/kW-mo.), and (2) the un-prorated capacity clearing price that the resources would have received absent price proration (4.50/kW-mo.), plus interest (total refunds with interest will total approximately $20.4 million);
- the parties to whom the resettlements would be charged (those with Regional Network Load within Connecticut during that time) and paid (the resource's Lead Market Participant during each month of FCA1); and
- the mechanism by which the ISO would make such resettlements.

The ISO did not identify any considerations that would render the resettlements inappropriate or difficult. For purposes of its brief, the ISO assumed a December 14, 2015 resettlement date. Initial briefs were also submitted by Bridgeport Energy, Dominion, and Bridgeport Energy. A reply brief was submitted on August 17 by Bridgeport Energy (requesting that payments be paid to the legal entity that owned the resource at the time of the FCA 1 Commitment Period or, if that legal entity no longer exists, to the successor in interest to ownership of the subject resource). On September 2, the ISO answered Bridgeport Energy's reply brief, advocating for resettlement payments to the Lead Market Participant during the first Capacity Commitment Period. 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) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **NCPC Credit Revisions (ER16-250)**

On November 3, the ISO and NEPOOL jointly filed changes to Market Rule 1 Appendix F to implement two revisions to the Net Commitment Period Compensation ("NCPC") credit rules (the "NCPC Credit Revisions") . Specifically, the NCPC Credit Revisions modify the NCPC rules to eliminate: (i) NCPC payments to cover commitment costs in the Real-Time Energy Market when a non-fast start resource is operating pursuant to a schedule it received in the Day-Ahead Energy Market; and (ii) the potential for a Market Participant with a resource that is self-scheduled in the Day-Ahead Energy Market to receive an NCPC credit when the Day-Ahead Energy Market clears at prices less than the Energy Offer Floor of $-150/MWh. The NCPC Credit Revisions were supported by the Participants Committee at its October 2, 2015 meeting (Consent Agenda Item # 5). A February 1, 2016 effective date was requested. Comments on this filing were due on or before November 24; none were filed. Interventions were filed by Dominion, Entergy, Eversource, Exelon, and National Grid. 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).

- **CSO Terminations: GMP (ER16-226); Enerwise (ER16-225); Direct Energy (ER16-224); Twin Eagle (ER16-223); and Brookfield White Pine Hydro (ER16-222)**

Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on October 30 to terminate, in whole or in part, as noted below, CSOs for the following Project Sponsors' resources:

- ♦ Brookfield White Pine Hydro: partial withdrawal of Resource No. 328
- ♦ Direct Energy Business Marketing, LLC: Resource Nos. 37928, 37933, 37934, 37938, and 37939
- ♦ Enerwise Global Technologies, Inc.: Resource Nos. 37927, 37093, and 37095
- ♦ Green Mountain Power Corporation ("GMP"): partial withdrawal of Resource No. 35728
- ♦ Twin Eagle Resource Management: partial withdrawal of Resource Nos. 1376, 1377, 1378, 1379, and 1380

The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the applicable amount of financial assurance provided by the Project Sponsors with respect to the CSOs or portions of the CSOs being terminated. Comments on these terminations are due on or before November 20. NEPOOL filed an intervention in each of the proceedings on November 13. These matters are pending before the FERC. If you have any questions concerning these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **DR Changes (ER16-167)**

As previously reported, the ISO and NEPOOL jointly filed on October 30 three sets of Tariff changes governing the participation of demand response resources ("DR") in the New England Markets ("DR Changes"). Specifically, the DR Changes (i) delay the full integration of DR into the New England Markets by one year (the "DR Delay Changes"); (ii) revise the methodology used to derive Demand Response Baselines (the "DR Baseline Changes"); and (iii) modify the simultaneous auditing requirements of Real-Time Demand Response and Real-Time Emergency Generation Resources (the "DR Simultaneous Auditing Changes"). The DR Delay Changes were supported by the Participants Committee at its September 11, 2015 meeting (Consent Agenda Item # 6); the DR Baseline and Simultaneous Auditing Changes, at the October 2, 2015 meeting (Consent Agenda Item #s 3 & 4). A December 31, 2015 effective date was requested for the DR Delay and Baseline Changes; a June 1, 2016 effective date for the DR Simultaneous Auditing Changes. Comments on this filing were due on or before November 20; none were filed. Doc-less interventions were filed by ConEd, Dominion, Emera, Entergy, Eversource, Exelon, National Grid, NESCOE, and NRG/GenOn. This mater is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Reactive Capability Auditing Revisions (ER15-2628)**

On November 12, the FERC accepted changes jointly filed by the ISO and NEPOOL to (1) add a new section III.1.5.3 to Market Rule 1 addressing reactive capability audits (in part in response to the proposed 2016 retirement of NPCC Directory #10); (2) add additional generation resource unit types to the provisions for real power audits; and (3) change the effective date for real power audits (from seven to one business day following notification of audit results). The revisions were accepted as of December 1, 2015, as requested. Unless the November 12 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).

- **Jump Ball Filing: Winter Reliability Program (ER15-2208)**

As previously reported, the FERC conditionally accepted, on September 11, NEPOOL's Winter Reliability Program Proposal as "just and reasonable and preferable … subject to ISO-NE submitting revised Tariff records in a compliance filing" due on or before October 26, 2015.[44] In that compliance filing, the ISO was directed to revise the Tariff to include the formula used to calculate the annual rate, rather than simply post that formula on the ISO website,[45] and to make certain corrections to NEPOOL's proposed Tariff revisions.[46] The ISO submitted its compliance filing, as directed, on October 26, 2015. On November 6, the Participants Committee voted unanimously to support the ISO's compliance filing (Consent Agenda Item #5). Comments supporting the compliance filing were filed on the November 16 comment date by NEPOOL and NEPGA. The compliance filing is now pending before the FERC.

As previously reported, the ISO and NEPOOL submitted, on July 17, two alternative versions of Market Rule changes intended to establish a winter reliability program for winters 2015/16, 2016/17 and 2017/18 -- the "NEPOOL Proposal" and the "ISO-NE Proposal". Both Proposals were intended to address reliability challenges created by the region's increased reliance on natural gas-fueled generation and to be stop-gap measures until revised incentives for capacity resources (PFP) become fully effective in 2018. The NEPOOL Proposal was

[44] *ISO New England Inc. and New England Power Pool Participants Comm.*, 152 FERC ¶ 61,190 (Sep. 11, 2015) at P 44.

[45] *Id.* at P 51.

[46] *Id.* at P 52.

based on the design of the 2014/15 program, with three main components: (1) compensation for certain oil inventory that remains in New England following the end of each winter period; (2) compensation for unused liquefied natural gas ("LNG") contract volumes; and (3) a supplemental demand response ("DR") program. The ISO Proposal also included the first two components of the NEPOOL Proposal, but eliminated the DR component, and provided compensation not only for fuel oil and LNG, but also for nuclear, hydro, biomass and coal-fired resources. In accepting the NEPOOL Proposal, the FERC noted that the NEPOOL Proposal was "widely supported in the region by a substantial majority of stakeholders representing all six NEPOOL stakeholder sectors."[47] The FERC disagreed with those that argued that NEPOOL's proposal was unduly discriminatory or represented a collateral attack on the FERC's prior orders, and disagreed with arguments that DR was incompatible with the Winter Program's objectives. The FERC also found that the 10-day inventory compensation cap is sufficient to incent participation in the program even if the additional resource types are not included. On October 13, Entergy challenged the September 11 order, asserting that the FERC should reverse itself and adopt the ISO-NE Proposal. On November 9, the FERC issued a tolling order affording it additional time to consider the Entergy request for rehearing, which remains pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Curve Changes (ER14-1639)**

As previously reported, the FERC denied rehearing of the *Demand Curve Order*,[48] but clarified (agreeing with Exelon and Entergy) that a resource that elects to utilize the renewables minimum offer price rule exemption should not also be allowed to utilize the new resource lock-in).[49] Accordingly, the FERC directed the ISO to submit, on or before March 2, 2015, a Compliance filing clarifying that a resource may not utilize both the renewable resource exemption and the new resource price lock-in. That Compliance filing was submitted on March 2, accepted on May 1, and became effective on May 2.[50] The petition for DC Circuit Court of Appeals review of the FERC's Demand Curve orders, filed by NextEra, NRG and PSEG, remains pending before that Court (*see* Section XV below).

NEPGA 206 Request. In response to the ISO's May 18, 2015 Informational Report and the announcement that the ISO does not intend to file sloped zonal demand curves, NEPGA filed on June 23 a request that the FERC "initiate a Section 206 proceeding on the ISO-NE Tariff and order ISO-NE to file the sloped zonal demand curves developed by ISO-NE and NEPOOL stakeholders, and proposed by ISO-NE as recently as April 2015 ("Zonal Curves"), for effect in FCA 10, amended to eliminate an FCA clearing rule ISO-NE had proposed as part of its Zonal Curves design." NEPGA asked that the ISO be compelled to make that filing within 30 days of that FERC order. The ISO answered and opposed NEPGA's request on July 2. Comments supporting the NEPGA request were filed by EPSA on July 7. NEPOOL submitted comments on July 8 (taking no position on whether an order to implement sloped zonal demand curves generally is appropriate or justified, or whether implementation can be achieved in time for FCA10, but if such an order were to be issued, urging that any Market Rule changes be fully discussed, and voted by NEPOOL pursuant to a schedule that allows the NEPOOL stakeholder process to proceed to completion and account for the many interrelated issues associated with such Market Rule changes. NEPOOL urged the FERC to reject the NEPGA request that the FERC order a specific solution that NEPOOL voted and did not support). NEPGA's motion remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[47] *Id.* at P 46.

[48] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*"), *reh'g denied but clarif. granted*, 150 FERC ¶ 61,065 (Jan. 30. 2015).

[49] *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,065, at P 27 (Jan. 30, 2015) ("*Demand Curve Clarification Order*").

[50] The changes become effective with FCA10, and will not apply to the resources in FCA9, totaling 12.96 MW, that utilize both the renewable resource exemption and the price lock-in election.

- **Jump Ball Filing: FCM Performance Incentives (ER14-1050)**

As noted in Section I above, the FERC, on November 19, denied rehearing, and dismissed as moot the requests for rehearing, of the *FCM PI Order*.[51] Requests for clarification and/or rehearing of the *PI Order* had been filed by NEPOOL, Connecticut and Rhode Island, Dominion, MMWEC, Indicated Generators, NEPGA, NextEra, Potomac Economics, and PSEG/NRG. Unless further challenged in the Federal Courts, this proceeding has been concluded. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Capability Resource Ratings Rehearing Request (ER11-2216)**

On November 12, the FERC denied a long pending MMWEC request for rehearing of the January 28, 2011 *Capability Clarifications Order*.[52] As reported previously, MMWEC requested rehearing of the *Capability Clarifications Order* on February 24, 2011, asserting that the FERC erred in rejecting its request for hearing and settlement procedures to establish the appropriate CNR rating for its Stony Brook facility. 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 was being reviewed. 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. Since that time, MMWEC neither withdrew its request for rehearing nor requested a ruling on the merits. Given the passage of time, and with the request remaining pending without apparent resolution, the FERC addressed the issues raised in the 2011 request, denying MMWEC's request.[53] If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Retirement of RTO Mapping Document (Tariff Attachment C) (ER15-2717)**

On November 17, the FERC accepted the changes that retire the RTO Mapping Document (Attachment C) from the Tariff. The RTO Mapping Document was created during the 2005 transition to the RTO arrangements as a guide for identifying where pre-RTO documents/provisions could be found under the RTO arrangements. The Mapping Document will remain available as a research aid on the ISO website (http://www.iso-ne.com/participate/governing-agreements/historicaldocuments). Unless the November 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CTS Conforming Changes (ER15-2641)**

On November 9, the FERC conditionally accepted the conforming changes to the ISO Tariff and the ISO-NE/NYISO Coordination Agreement, jointly filed by the ISO, NEPOOL, and PTO AC, to support the implementation of Coordinated Transaction Scheduling between New England and New York over the New York Northern AC interface ("CTS"), a project to be completed in December 2015.[54] As previously reported, the CTS Conforming Changes were supported by the Participants Committee at its August 7, 2015 meeting. The

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[51] *ISO New England Inc. and New England Power Pool*, 153 FERC ¶ 61,223 (Nov. 19, 2015).

[52] *ISO New England Inc. and the Participating Trans. Owners Admin. Comm.*, 134 FERC ¶ 61,057 (Jan. 28, 2011) ("*Capability Clarifications Order*"), *reh'g denied*, 153 FERC ¶ 61,163 (Nov. 12, 2015). The revisions to the Tariff accepted by 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").

[53] *ISO New England Inc. and the Participating Trans. Owners Admin. Comm.*, 153 FERC ¶ 61,163 (Nov. 12, 2015).

[54] *ISO New England Inc., New England Power Pool Participants Comm., and the Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,159 (Nov. 9, 2015).

conforming changes were accepted with an effective date on or after December 1, 2015, subject to two weeks prior notice to be filed identifying the actual effective date. In accepting the changes, the FERC identified 3 corrections to be made to the Tariff provisions, which it directed be filed with the effective date notice. Challenges, if any, to the November 9 order must be filed on or before December 9.

Notice of December 15, 2015 Effective Date and Tariff Corrections. On December 1, the ISO filed notice that CTS will become effective ***December 15, 2015***, It also filed the minor corrections directed by the November 9 order. Comments, if any, on the notice and corrections are due on or before December 22. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000*** **Interregional Compliance Filings (ER13-1960; ER13-1957)**

As previously reported, the FERC conditionally accepted, subject to Compliance filings made July 13, revisions to the ISO Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* and (ii) an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Protocol").[55] The First *Order 1000 Interregional Compliance Changes* included (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.

Second Order 1000 Interregional Compliance Changes. On November 19, the FERC accepted the revisions to the ISO-NE Tariff and to the Protocol filed July 13 by the ISO in response to the *Order 1000 Interregional Compliance Filing Order* ("Second *Order 1000* Interregional Compliance Changes"). Unless the November 19 order is challenged, the *Order 1000* Interregional Compliance proceedings will be concluded. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000*** **Regional Compliance Filings (ER13-193; ER13-196)**

Since the last Report, the FERC issued an October 2, 2015 order granting the ISO's pending request for rehearing and clarification of the March 19 *Order 1000 Compliance Rehearing Order* and conditionally accepting the 3rd Regional Order 1000 Compliance filing, subject to a further compliance filing (which was submitted on November 2).[56]

ISO Request for Clarification and/or Rehearing. As previously reported, the ISO requested clarification and/or re-hearing of the FERC's March 19, 2015 *Order 1000 Compliance Rehearing Order*.[57] Specifically, the ISO requested clarification (i) that the FERC's concerns with the non-discriminatory applicability of the "hold harmless" clause contained in the Non-Incumbent Transmission Developer Operating Agreement ("NTDOA") could be addressed by the inclusion of a similar clause in the Transmission Operating Agreement ("TOA"); and (ii) that no changes are required to comply with Regional Cost Allocation Principle 4 and that language providing that "the costs of any external impacts of New England regional projects will not be borne by New England customers" need not be removed from Schedule 15 of the OATT. In the *October 2 Order*, the FERC granted clarification with respect to (i) and granted rehearing with respect to (ii). In light of its granting of clarification with respect to (i), the FERC found moot and directed

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[55] *ISO New England Inc.*, 151 FERC ¶ 61,133 (May 14, 2015) ("*Order 1000 Interregional Compliance Filing Order*").

[56] *ISO New England Inc.*, 153 FERC ¶ 61,012 (Oct. 2, 2015) ("*October 2 Order*").

[57] *ISO New England Inc.*, 150 FERC ¶ 61,209 (Mar. 19, 2015) ("*Order 1000 Compliance Rehearing Order*"), *clarif. and reh'g granted*, 153 FERC ¶ 61,012 (Oct. 2, 2015). A memo summarizing the 200-page Mar. 19 order in more detail was circulated by NEPOOL Counsel on Mar. 23 and posted on the NEPOOL website Litigation Report Updates page.

the ISO to remove the proposals in the 3rd Regional Order 1000 Compliance Filing to modify the definition of a Non-Incumbent Transmission Developer and establish when a PTO be deemed a Qualified Transmission Project Sponsor.[58] With respect to (ii), the FERC found "upon further review that Filing Parties' proposal sufficiently identifies the extent to which they will assume the cost consequences that a regional transmission project has on a neighboring region's transmission system."[59]

3rd Regional Order 1000 Compliance Filing. The FERC found that the May 18 3rd Regional Order 1000 Compliance Filing partially complied with the March 19 order.[60] In particular, the FERC found consistent with its directives the removal of language allowing the ISO to require a PTO to continue development of the Backstop Transmission Solution beyond the point of a Qualified Sponsor's acceptance of responsibility for a selected transmission project. However, the FERC also found that certain revisions retained from the Second Compliance Filing were not directed by the FERC, and directed the ISO to remove these revisions.[61] The FERC found it "unnecessary to require Filing Parties to make LS Power's proposed revisions to the definition of Backstop Transmission Solution to make it clear that such a solution is only a Phase One or Phase Two submittal until such time as the more efficient or cost-effective transmission project is replaced by the Backstop Transmission Solution."[62]

4th Regional Order 1000 Compliance Filing. On November 2, the ISO and PTOs submitted a 4th compliance filing in response to the directives and requirements in the *October 2 Order*.[63] The 4th Regional Compliance Filing was supported by the Participants Committee at its November 6 meeting. Comments supporting the 4th Compliance Filing were submitted by NEPOOL on November 23, 2015; no other comments were filed. The 4th Regional Compliance Filing is pending before the FERC.

If you have any comments or concerns on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **Estimation of Hourly Charges (ER16-286)**

On November 6, the ISO and NEPOOL jointly filed changes to modify how the collateral requirements related to a Market Participant's Hourly Charges are estimated. These changes were supported by the Participants Committee at its meeting earlier that day. An effective date of January 8, 2016 was requested. Comments on this filing were due on or before November 27; none were filed. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedules 20A-ES & 21-ES: Eversource Updates (ER16-348)**

On November 18, Eversource filed changes to change the title of Schedules 20A-NU and 21-NU to Schedule 20A-ES and 21-ES, respectively, and to replace all references to NU and Northeast Utilities therein to ES and Eversource. A January 18, 2016 effective date was requested. Comments on this filing are due on or

[58] *October 2 Order* at P 28.

[59] *Id.* at P 50.

[60] *Id.* at P 12.

[61] *Id.* at P 43.

[62] *Id.* at P 45.

[63] *Id.* at P 12.

before December 9. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Corrections (ER16-273)**

On November 6, Emera Maine filed corrections to Schedule 21-EM. Emera reported that the correction, in Attachment P-EM, revises the definition of "Other Transmission-Related Regulatory Assets/Liabilities" to include liabilities associated with post-retirement benefits as recorded in Account No. 228.3, ultimately resulting in a lower transmission revenue requirement. A June 1, 2015 effective date was requested. Comments on the corrections were due November 21; none were filed. 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 22: Granite Ridge LGIA (ER15-2747)**

On November 13, the FERC accepted a non-conforming, 4-party LGIA between the ISO, Granite Ridge as Interconnection Customer, and both National Grid and Eversource (on behalf of PSNH) as Interconnecting Transmission Owners. The LGIA is non-conforming in that it contains certain deviations from Schedule 22's *pro forma* LGIA necessary to accommodate two Interconnecting TOs. The LGIA governs the interconnection of Granite Ridge's Londonderry, NH facility, unique in that, while the facility operates in a single combined cycle configuration such that the individual units comprising the facility cannot be separated, the facility's combustion and steam turbines were interconnected at two different points on the System. The need for a new LGIA was initiated by a proposed increase in the output of the facility. The LGIA was accepted effective as of August 31, 2015, as requested. Unless the November 13 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).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **128th Agreement: GIS-Only Participant Status (ER16-214)**

On October 30, NEPOOL filed amendments to the NEPOOL Agreement to incorporate a "GIS-Only Participant" status into the governance arrangements. A "GIS-Only Participant" is a Participant that meets four criteria: (1) owns or controls one or more GIS certificates; (2) does not participate directly in the New England Markets; (3) is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (4) elects to be treated as a GIS-Only Participant. A GIS-Only Participant will be treated like any other Participant for all purposes, other than with respect to a limitation on such a Participant's ability to make motions and vote (which will be limited to GIS matters only). These changes were approved by the Participants Committee by way of the 128th Agreement Amending the NEPOOL Agreement. Comments on this filing were due on or before November 20, 2015; none were filed. A doc-less intervention was filed by National Grid. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **129th Agreement: Review Board Removal (ER16-159)**

On October 29, NEPOOL and the ISO jointly filed amendments to the NEPOOL Agreement and Participants Agreement to remove from those documents the requirement that NEPOOL continue to maintain the NEPOOL Review Board. These changes were approved by the Participants Committee by way of the 129th Agreement Amending the NEPOOL Agreement and Amendment No. 9 to the Participants Agreement. Comments on this filing were due on or before November 19, 2015; none were filed. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports

- **Capital Projects Report - 2015 Q3 (ER16-94)**

On November 24, the FERC accepted the ISO's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2015 (the "Report"). As previously reported, Q3 Report highlights included the following new projects: (i) Power System Modeling Management Initiatives ($420,000); (ii) NX9/NX12D – Generator Voltage Data ($355,000); and (iii) Visitor Management ($260,000). The Report noted that $300,000 assigned for the PRD project in 2015 will not be allocated given the uncertainty around *Order 745* and $100,000 has been allocated in the 2016 Budget for PRD work. Comments supporting the Q3 Report were filed by NEPOOL. A doc-less motion to intervene was filed by Eversource. Unless the November 24 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).

- **Demand Curve Changes Progress Reports (ER14-1639)**

On October 30, the ISO reported that, since its last progress report on May 18, it has been evaluating approaches to developing zonal demand curves for the capacity market., and as a result, has a conceptual proposal to use the ISO's full-scale reliability planning simulation system ("GE MARS") to develop zonal demand curves for each FCA on an annual basis. Under this approach, the annual simulation process would be conducted according to a consistent set of design principles reflecting reliability, sustainability and cost-effectiveness. The ISO presented this approach at the October 8, 2015 Markets Committee meeting. The ISO stated that its current tentative schedule calls for Participants Committee consideration of its zonal demand curve proposal at the NPC's April 2016 meeting, with a FERC filing shortly thereafter. This informational report has not been noticed for public comment.

- ***Opinion 531-A* Refund Report: FG&E (EL11-66)**

On June 29, 2015, FG&E filed its refund report for its customers taking local service during the refund period in accordance with *Opinion 531-A*. Comments, if any, on this filing were due on or before July 20; 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).

- **ISO-NE FERC Form 3Q (2015/Q3) (not docketed)**

On November 17, the ISO submitted its 2015/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **December 2015 Membership Filing (ER16-428)**

On November 30, NEPOOL requested that the FERC accept (i) the membership of Niagara Wind Power (Related Person of First Wind/SunEdison, AR Sector); Residents Energy (Related Person of IDT Energy, Supplier Sector); and Utility Expense Reduction (Supplier Sector); and (ii) termination of the Participant status of Barclays Bank (Supplier Sector) and Twin Cities Power (Related Person of Town Square Energy, Supplier Sector). Comments on this filing are due on or before December 20, 2015.

- **November 2015 Membership Filing (ER16-192)**

On October 30, NEPOOL requested that the FERC accept (i) the membership of CommonWealth Resource Management Corporation (AR Small RG Group Member); Everyday Energy, LLC (Related Person of Viridian Energy, Supplier Sector); Shipley Choice, LLC d/b/a Shipley Energy (Supplier Sector); SRECTrade, Inc. (GIS-Only Participant); and Lotus Danbury LMS100 One and Lotus Danbury LMS100 Two (Provisional Group Member); (ii) INVOLUNTARY termination of the Participant status of Demansys (AR Small LR Group

Member); and (iii) voluntary termination of the Participant status of MoArk and Turner Energy (End User Sector). This matter is pending before the FERC.

- **October 2015 Membership Filing (ER16-1)**

On November 13, the FERC accepted (i) the membership of Antrim Wind Energy (Provisional Group Member), Astral Energy (Supplier Sector), Beacon Falls Energy Park (Related Person to Kleen Energy – Generation Sector), Champlain VT (Provisional Group Member), Concord Steam Corporation, (Provisional Group Member), Deepwater Wind Block Island (AR Sector, Large AR Group Seat), Invenergy Energy Management (Provisional Group Member), and MA Operating Holdings (Related Person to SunEdison– AR Sector, RG Sub-Sector); (ii) termination of the Participant status of HOP Energy (Supplier Sector), energy.me (Supplier Sector), Parkview AMC Energy (MPEU), Denver Energy (Related Person to Peninsula Power - Supplier Sector), and Johnston Clean Power (Provisional Group Member); and (iii) the name change of NRG Curtailment Solutions, Inc. (f/k/a Energy Curtailment Specialists).

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 2015 (NP16-3)**

NERC submitted on November 30, 2015 its Find, Fix, Track and Report ("FFT") informational filing for the month of November 2015. As it did for the October FFT, NERC provided no public information regarding the number of possible violations resolved or the number of Reliability Standards implicated.[64] Given the lack of information provided in the public version of FFT filings, the FFT Reports will no longer be included in the Litigation Report.

- **Revised Reliability Standards: IRO-006-EAST-2; IRO-009-2 (RD15-7)**

On September 16, 2015, NERC filed for approval changes to IRO-006-EAST-2 (Transmission Loading Relief Procedure for the Eastern Interconnection) and IRO-009-2 (Reliability Coordinator Actions to Operate within IROLs). NERC states that IRO-006-EAST-2 removes redundant requirements based on Paragraph 819 criteria, revises existing language to clearly delineate applicable entities and the specific actions required, and relocates information in bullet points and subparts to the Requirements. IRO-009-2 combines two existing requirements, revises existing language to clearly delineate applicable entities and the specific actions required, and removes unnecessary language. NERC adds that both Standards implement language revisions and format improvements for consistency with recent Board-approved Reliability Standards. Comments on this filing were due on or before October 19, 2015; none were filed. This mater is pending before the FERC.

- **Revised Reliability Standards: PRC-004-5; PRC-010-2 (RD15-5)**

On November 19, the FERC approved changes to PRC-004-5 (Protection System Misoperation Identification and Correction) and PRC-010-2 (Under Voltage Load Shedding). The Reliability Standards address misoperation of undervoltage load shedding ("UVLS") equipment and were developed as Phase 2 of NERC's pending proposal to consolidate UVLS Program Reliability Standards. PRC-004-5 and PRC-010-2 became effective on November 19, 2015.

- ***Order 817*: Revised TOP and IRO Reliability Standards (RM15-16)**

On November 19, the FERC approved changes reflected in the following Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards:[65]

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[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 (Mar. 15, 2012) at PP 46-56.

[65] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (Nov. 19, 2015) ("*Order 817*").

- TOP-001-3 (Transmission Operations);
- TOP-002-4 (Operations Planning);
- TOP-003-3 (Operational Reliability Data);
- IRO-001-4 (Reliability Coordination – Responsibilities);
- IRO-002-4 (Reliability Coordination –Monitoring and Analysis);
- IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-2 (Reliability Coordinator Data Specification and Collection);
- IRO-014-3 (Coordination Among Reliability Coordinators); and
- IRO-017-1 (Outage Coordination).

In approving *Order 817*, the FERC required NERC to make three modifications to the Standards within 18 months of the effective date of the final rule. *Order 817* will become effective on January 26, 2016.[66]

- **NOPR: Revised Reliability Standards: CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2, CIP-011-2 (RM15-14)**

On July 16, 2015, the FERC issued a NOPR proposing to approve changes to seven CIP ("Critical Infrastructure Protection") Reliability Standards to improve the cyber security protections required by the CIP Standards and address four directives from *Order 791* (the "Supply Chain Cyber Controls Changes").[67] NERC stated that the Supply Chain Cyber Controls Changes (i) remove the "identify, assess, and correct" language from the 17 requirements in the CIP Version 5 Standards that included such language; (ii) require responsible entities to implement cyber security plans for assets containing low impact BES Cyber Systems; (iii) include specific requirements applicable to transient devices to further mitigate the security risks associated with such devices; and (iv) require entities to implement security controls for non-programmable components of communication networks at Control Centers with high or medium impact BES Cyber Systems. NERC requested that the Supply Chain Cyber Controls be approved, effective on **April 1, 2016**. Comments on the *Revised CIPs NOPR* were due on or before September 21, 2015,[68] and were filed by over 40 parties, including NERC, ISO-NE, NextEra, and APPA/EEI/EPSA/ELCON/NRECA et al. On October 28, the FERC issued a notice of technical conference to be held on January 28, 2016. The technical conference will facilitate dialogue on supply chain risk management issues identified by the FERC in the NOPR. Technical Conference panelists may be asked to address: (1) the NOPR proposal to direct that NERC develop a Reliability Standard to address supply chain risk management; (2) the anticipated features of, and requirements that should be included in, such a standard; and (3) a reasonable timeframe for development of a standard. Those wishing to participate in the panel discussions should submit nominations by November 20.

- ***Order 818*: Revised Reliability Standards: Transition to "Remedial Action Scheme", PRC-010-1, EOP-011-1 (RM15-13, RM15-12; RM15-7)**

On November 19, the FERC issued *Order 818*[69] approving three related NERC petitions that revise (i) the definition of "Remedial Action Scheme" and nearly 20 Reliability Standard to insert that term in place of the term "Special Protection System", which are used interchangeably throughout the Reliability Standards (the "RAS Changes") (RM15-13); (ii) PRC-010-1 (Undervoltage Load Shedding), a definition of "Undervoltage Load Shedding Program (UVLS Program)", and associated VRFs and VSLs (together, the "UVLS Changes") (RM15-

[66] *Order 817* was published in the *Fed. Reg.* on Nov. 27, 2015 (Vol. 80, No. 228) pp. 73,977-73,991.

[67] *Revised Critical Infrastructure Protection Reliability Standards*, 152 FERC ¶ 61,054 (July 16, 2015) ("*Revised CIPs NOPR*").

[68] The *Revised CIPs NOPR* was published in the *Fed. Reg.* on July 22, 2015 (Vol. 80, No. 140) pp. 43,354-43,367.

[69] *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228 (Nov. 19, 2015) ("*Order 818*").

12); and (iii) EOP-011-1 (Emergency Operations), a revised definition of "Energy Emergency", and associated VRFs and VSLs (together, the "Emergency Operations Changes") (RM15-7). *Order 818* will become effective on January 26, 2016.[70]

- **NOPR: New Reliability Standard: TPL-007-1 (RM15-11)**

On May 14, 2015, FERC issued a NOPR proposing to approve a new Reliability Standard -- TPL-007-1 (Geomagnetic Disturbance Operations) -- and one new definition (Geomagnetic Disturbance Vulnerability Assessment), associated VRFs and VSLs (together, the "GMD Operations Changes").[71] In addition, the FERC proposes to direct NERC (i) to develop modifications to the benchmark GMD event definition set forth in TPL-007-1 Attachment 1 so that the definition is not based solely on spatially-averaged data and (ii) to submit a work plan, and subsequently one or more informational filings, that address specific GMD-related research areas. As previously reported, NERC stated that the GMD Operations Changes address the FERC's directive in *Order 779* that NERC develop a Reliability Standard that requires owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark geomagnetic disturbance events on the Bulk-Power System equipment and the Bulk-Power System as a whole.[72] NERC requested the FERC approve a five-year phased implementation plan for Compliance with TPL-007-1. Comments on this NOPR were due on or before July 27, 2015[73] and were filed by over 20 parties, including ISO-NE/NYIOS/PJM/MISO/IESO, EEI, Exelon, and NERC. On August 17, NERC filed a notice that the appeal panel appointed under NERC's process for Standards appeals had concluded NERC appeal proceedings by using a final decision finding that the objections of appellant Foundation for Resilient Societies, Inc. were afforded fair and equitable treatment during the TPL-007-1 development process. Comments on that panel's decision were due and filed by September 10. On October 2, the FERC issued a notice that comments on Foundation for Resilient Societies' filing of a September 2015 technical paper prepared by the Los Alamos National Laboratory entitled "Review of the GMD Benchmark Event in TPL-007-1" as well as on NERC's September 10 comments should be filed on or before October 22. Comments were filed by 8 parties. In addition, On November 2, D. Bardin requested official notice of National Space Weather Strategy and NSW Action Plan. On November 4, EEI, APPA, ECRC, and NRECA filed additional comments. Since the last Report, additional and reply comments were submitted by D. Bardin, U.S. Geological Survey, Southern Company, IEEE PES Transformers Committee, and Storm Analysis Consultants & Advanced Fusion Systems. This matter remains pending before the FERC.

- **NOPR: New Reliability Standard: PRC-026-1 (RM15-8)**

On September 17, 2015, the FERC issued a NOPR proposing to approve PRC-026-1 (Relay Performance During Stable Power Swings) and associated VRFs and VSLs (the "PRC-026 Standard"). As previously reported, the PRC-026 Standard was filed in response to the FERC's directive to NERC in *Order 733*[74] to develop a Reliability Standard addressing undesirable relay operation due to stable power swings. NERC requested that PRC-026 be approved, effective as follows: R1 on the first day of the first full calendar year that is 12 months after FERC approval; R2-R4 on the first day of the first full calendar year that is 36 months after FERC approval. Comments on this NOPR were due on or before November 23, 2015[75] and were submitted by NERC, Luminant, EEI, Idaho Power, ITC, North American Generator Forum, and the Tri-State Generation and Transmission Association. This matter is pending before the FERC.

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[70] *Order 818* was published in the *Fed. Reg.* on Nov. 27, 2015 (Vol. 80, No. 228) pp. 73,647-73,658.

[71] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 151 FERC ¶ 61,134 (May 14, 2015) ("*TPL-007 NOPR*").

[72] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 ("*Order 779*").

[73] The *TPL-007 NOPR* was published in the *Fed. Reg.* on May 26, 2015 (Vol. 80, No. 100) pp. 29,990-30,001.

[74] *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 (2010); *order on reh'g and clarif.*, Order No. 733-A, 134 FERC ¶ 61,127 (2011); *clarified*, Order No. 733-B, 136 FERC ¶ 61,185 (2011) ("*Order 733*").

[75] The *PRC-026 NOPR* was published in the *Fed. Reg.* on Sep. 24, 2015 (Vol. 80, No. 185) pp. 57,549-57,553.

- **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

The MOD-001-2 NOPR remains pending before the FERC. On June 19, 2014, the FERC issued a NOPR proposing to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) ("MOD Changes") proposed by NERC. The MOD Changes replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC"). MOD-001-2 will replace the six Existing MOD Standards[76] to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2's effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC seeks comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also seeks further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,[77] and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. Since the last Report, NASEB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the NAESB WEQ Business Practice Standards in October 2015. As noted above, the MOD-001-2 NOPR remains pending before the FERC.

- **NOPR: BAL-002-1a Interpretation Remand (RM13-6)**

This May 16, 2013 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.[78] 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,[79] and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR remains pending before the FERC.

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[76] The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

[77] The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

[78] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[79] The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

- **Compliance Filing: BES Exclusions for Local Network Configurations (RM12-6)**

On July 1, 2015, NERC submitted, pursuant to *Order 773*, a Compliance filing identifying in detail the types of local network configurations that may be excluded from the bulk electric system ("BES") following the implementation of the revised definition of the BES under Exclusion E3 of that definition. As of the date of this Report, the FERC has not noticed the Compliance filing or otherwise invited public comment.

- **Revised Regional Delegation Agreements (RR15-12)**

On November 2, the FERC conditionally accepted a revised *pro forma* and individual Regional Delegation Agreements with each of the eight Regional Entities, including NPCC (the "RDAs"), filed by NERC to be effective January 1, 2016.[80] In accepting the RDAs, the FERC required that NERC submit changes on or before March 1, 2016 (i) to revise section 8(f) of the RDA as directed to ensure that the RDA accounts for the required NERC audits of Regional Entities in accordance with the NERC Rules of Procedure and provides NERC the flexibility to perform reviews it deems necessary on a reasonable periodicity; (ii) to revise section 8(g) as directed in order to grant the FERC full access to the non-public material resulting from these activities; (iii) to modify the RDAs so that they are subject to FERC re-evaluation and re-approval following the initial term, scheduled to end on December 31, 2020; (iv) to remove the proposed automatic renewal provisions and re-insert audit provisions in section 12(b) that had been proposed to be removed; (v) to revise section 3(b) of the RDAs to include a provision requiring NERC to maintain on its public website the currently effective versions of all of the Regional Entities' bylaws and regional standard development procedures; (vi) to clarify the meaning of other "guidance that NERC may from time to time develop," and that its guidance on reporting to the FERC instances of noncompliance of Reliability Standards and their disposition must be filed with the FERC for approval before it becomes effective; and (vii) to include language in RDA section 15 stating that Section 1500 of the NERC Rules of Procedure controls when a conflict between it and the RDAs may arise.

- **E. Morris v. NERC/SERC (EL15-93)**

On December 2, 2015, the FERC dismissed the complaint and petition for rulemaking filed by Eric S. Morris ("Morris") against NERC and SERC Reliability Corporation ("SERC") (collectively, "Respondents").[81] As previously reported, Morris alleged that Respondents violated NERC's Rules of Procedure Appendix 4B Sanction Guidelines in assessing a penalty on Entergy (*see* NP15-31, filed July 30, 2015) and failed to follow the Sanction Guidelines by failing to clearly identify that an alternative frequency or duration was used in determining the penalty and providing no supporting rationale. Morris asked that the Notice of Penalty be withdrawn or denied, and resubmitted with either the clear identification of the alternative frequency and duration with rationale or with a settlement base amount "re-adjusted into the multi-million dollar range." In dismissing the complaint and rulemaking petition, the FERC found (i) that Respondents were not subject to a complaint pursuant to section 306 of the Federal Power Act ("FPA"); and (ii) that Morris had "not shown that there is a sufficient problem to merit a generic solution through a rulemaking."[82] Unless the December 2 order is challenged in Federal Court, this matter will be concluded.

XI. Misc. - of Regional Interest

- **203 Application: Calpine/Granite Ridge (EC16-19)**

On October 27, 2015, Calpine Granite Holdings, LLC ("Calpine") and Granite Ridge Energy, LLC ("Granite Ridge") requested FERC authorization for the acquisition by Calpine of 100% of the membership interests of Granite Ridge. Comments on this filing are due on or before November 17, 2015; none were filed. This mater is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[80] *N. Amer. Elec. Rel. Corp.*, 153 FERC ¶ 61,135 (Nov. 2, 2015).

[81] *Eric S. Morris v. N. Amer. Elec. Rel. Corp and SERC Rel. Corp.*, 153 FERC ¶ 61,266 (Dec. 2, 2015).

[82] *Id.* at P 2.

- **203 Application: Passadumkeag Wind Park (SunEdison/ Quantum) (EC15-217)**

On November 17, 2015, the FERC authorized a transaction whereby the membership interests in the owner of Passadumkeag Wind Park will be acquired by SunEdison. Quantum and SunEdison must notify the FERC within 10 days of the date that the disposition of jurisdictional facilities has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Iberdrola/CMP/ Emera (EC15-103)**

On June 2, the FERC authorized a transaction whereby UIL Holdings Corp ("UI") will become an indirect, wholly-owned subsidiary of Iberdrola, S.A (and a Related Person of Central Maine Power Company, Iberdrola Renewables, LLC, and New York State Electric & Gas Corporation).[83] Iberdrola and UI must notify the FERC within 10 days of the date that the disposition of jurisdictional facilities has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PURPA Complaint: Allco Renewable Energy v. CT Agencies (EL16-11 et al.)**

On November 9, 2015, Allco Renewable Energy Limited ("Allco") petitioned the FERC to pursue an enforcement action under the Public Utility Regulatory Policies Act of 1978 ("PURPA") against the Connecticut Department of Energy and Environmental Protection ("DEEP") and the Connecticut Public Utilities Regulatory Authority ("PURA") (collectively, the "CT Agencies").[84] Allco seeks a FERC order that would remedy the CT Agencies' "improper implementation of PURPA" (with respect to a July 2013 solicitation and a procurement under newly enacted Section 1(c) of Connecticut Public Act 15-107). On November 30, CT Agencies filed their protest to the Complaint. Doc-less interventions were filed by Eversource, Exelon, National Grid and UI. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FirstEnergy PJM DR Complaint (EL14-55)**

On May 23, 2014, the same day that DC Circuit vacated *Order 745* (*see* Section XV below), FirstEnergy filed a complaint against PJM requesting that the FERC require the "removal of all portions of the PJM Tariff allowing or requiring PJM to include demand response as suppliers to PJM's capacity markets." FirstEnergy also requested that the results of the PJM capacity auction due to be released that same day, to the extent it included and cleared demand response resources, be considered void and legally invalid. PJM's response, and all comments and interventions were initially due on or before June 12, 2014. However, on June 11, the FERC extended that date to 30 days after the submission by FirstEnergy of an amended complaint. FirstEnergy filed its amended complaint on September 22, 2014.

Comments on the FirstEnergy Complaint were due October 22, 2014. More than 40 parties filed comments or responses to the FirstEnergy amended complaint. Many parties filed comments supporting the complaint (including Calpine, PSEG and PPL), while others opposed the complaint in its entirety (including Direct Energy and Enerwise). PJM's response argued that the complaint failed to justify the market disruption that would result from recalculating past capacity auction results, PJM was instead more focused on minimizing "litigation risk." A number of parties filed supporting comments in favor of removing demand response resources from the PJM tariff moving forward, but opposed to recalculating the results of past capacity auctions (including Exelon, the PJM IMM and NRG). Comments were also filed by National Grid and NYISO. A number of New England parties intervened, including NEPOOL (stressing that the FERC should not apply any ruling in this docket to the New England Market), Dominion, Duke Energy, Dynegy, Essential Power, Macquarie Energy, NEPGA, NESCOE, and NextEra. On November 14, FirstEnergy filed an answer to the answers, protests and comments submitted in response to its Complaint and Amended

[83] *Iberdrola, S.A. et al.*, 151 FERC ¶ 62,148 (June 2, 2015).

[84] Section 210(h)(2) of PURPA permits the FERC to initiate, and for QFs to petition the FERC to initiate, an enforcement action against a State regulatory authority for failure to implement the FERC's PURPA regulations. If the FERC declines to initiate an enforcement action, the petitioning QF then has the right to bring an action in the appropriate U.S. district court to enforce the PURPA regulations.

Complaint. Environmental Advocates[85] filed an answer to FirstEnergy's answer on November 21. Since the last Report, CPower and Advanced Energy Management Alliance filed answers to the FirstEnergy and other answers and pleadings. On December 23, Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Jamie Blackburn (jblackburn@daypitney.com; 202-218-3905) or Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – PSNH/Schiller Generating Station (ER16-391)**

On November 25, Eversource (PSNH) filed a two-party LGIA with Schiller Generating Station (a previously existing interconnection) to demonstrate compliance with REC Purchase Agreements and to formalize the existing LGIA. PSNH is the owner and operator of Schiller Station, located in Portsmouth, New Hampshire, a 180 MW, four-unit power plant, consisting of two coal-fired steam units, one wood-fired steam unit and one combustion turbine. A January 1, 2016 effective date was requested. Comments, if any, on the LGIA are due on or before December 16, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PSNH/NHEC Design & Engineering Agreement Cancellation (ER16-357)**

On November 19, Eversource (PSNH) filed a notice of cancellation of a Design and Engineering Agreement with New Hampshire Electric Cooperative ("NHEC"). The Agreement documented understandings related to the co-location of certain distribution level (12.47 kV) facilities onto distribution structures to be owned, operated and maintained by PSNH in Deerfield, New Hampshire. Eversource indicated that the Agreement expired in accordance with its terms on June 1, 2015. Accordingly, an June 1, 2015 effective date was requested. Comments, if any, on the cancellation are due on or before December 10, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CPV Towantic EDPS Agreement Cancellation (ER16-356)**

Also on November 19, Eversource filed a notice of cancellation of an Engineering, Design, Permitting, and Siting Services Agreement ("EDPS Agreement") between Eversource (CL&P) and CPV Towantic. Eversource indicated that the Agreement expired in accordance with its terms on April 13, 2015. Accordingly, an April 13, 2015 effective date was requested. Comments, if any, on the cancellation are due on or before December 10, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Wyman 4 Transmission Agreement (ER16-272)**

On November 5, CMP filed a third supplement to the Wyman Transmission Agreement. The Wyman Transmission Agreement sets forth the terms and conditions associated with the charges for transmission services by assigning cost responsibility to the joint owners of William F. Wyman Unit No. 4. for certain relocated 115kV facilities and for one 345kV circuit, including terminal facilities and associated interconnection equipment. The changes filed by CMP (i) revise definition of Transmission Facilities (the revisions resulting from certain modifications to the transmission system due in part to CMP's recent construction of the Maine Power Reliability Program Project.); (ii) update identities of owners; and (iii) clarify references to the ISO Tariff. A January 5, 2016 effective date was requested. Comments on this filing were due November 26; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[85] "Environmental Advocates" are Sustainable FERC Project, Natural Resources Defense Council ("NRDC"), Sierra Club, Environmental Defense Fund, Environmental Law and Policy Center, and Acadia Center (f/k/a Environment Northeast).

- **Emera MPD OATT Changes (ER15-1429)**

On April 1, Emera Maine filed changes to the Open Access Transmission Tariff ("OATT") for Maine Public District ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J. Emera Maine, as successor to Maine Public Service Company ("Maine Public"), provides open access to Emera Maine's transmission facilities in northern Maine (the "MPD Transmission System") pursuant to the MPD OATT. The changes to the MPD OATT are needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1, 2015 effective date was requested. On April 9, the "Maine Customer Group"[86] filed a motion to reject ("Motion to Reject") the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD's 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75% to 10.20% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine's predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group's Motion to Reject. On April 29, the Maine Customer Group answered Emera Maine's April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing, in part reflecting 2014 FERC Form 1 data rather than estimated data. On May 7, Emera Maine answered the April 22 Maine PUC and MCG protests and the MCG's April 29 answer. On May 8, MCG moved to compel revision to Emera's May 1 filing, asserting that it was not filed in accordance with Emera's OATT, and specifically the Protocols for Implementing and Reviewing Charges Established by the Attachment J Rate Formulas (the "Protocols"). MCG also protested the May 1 filing on May 22. On May 26, Emera Maine answered MCG's May 8 Motion to Compel, which MCG answered the next day. This matter remains pending before the FERC.

- **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",87 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. MISO (now called "Midcontinent Independent System Operator, Inc.") moved to lodge a NYISO "Broader Regional Markets Informational Report" filed March 19, 2014 in ER08-1281 and a related January 16, 2014 "Ontario-Michigan Interface PAR Performance Evaluation Report" ("Evaluation Report") prepared by MISO, IESO and PJM. Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, and PSEG.

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[86] The "Maine Customer Group ("MCG") is comprised of: the Maine Office of the Public Advocate ("MOPA"), Houlton Water Company ("Houlton"), Van Buren Light and Power District ("Van Buren"), and Eastern Maine Electric Cooperative, Inc. ("EMEC").

[87] *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) ("*MISO Initial Decision*") at P 923.

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).

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff notice of alleged violation, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Berkshire Power Company/Powerplant Management Services. On October 23, 2015, the FERC issued a notice that Staff of the Office of Enforcement ("OE") has preliminarily determined that Berkshire Power Company and Powerplant Management Services violated the FERC's Anti-Manipulation Rule by engaging in a manipulative scheme to conceal maintenance work and associated outages beginning at least as early as January 2008 and continuing through March 2011. In addition Staff alleges that Berkshire violated FERC-approved Reliability Standards (by failing to provide outage information to its Transmission Operator and failing to inform its Transmission Operator and Host Balancing Authority of all generation resources available for use) and FERC's Market Behavior Rules (by failing to comply with various provisions of the ISO Tariff and by making false and misleading statements to the ISO regarding its maintenance work and associated outages).

Coaltrain Energy/Co-Owners/Traders/Analyst. On September 11, 2015, the FERC issued a notice that OE has preliminarily determined that Coaltrain Energy L.P. ("Coaltrain"); its co-owners Peter Jones and Shawn Sheehan; traders Robert Jones, Jeff Miller, and Jack Wells; and analyst Adam Hughes violated the FERC's Anti-Manipulation Rule by executing a scheme involving manipulative PJM Up-To Congestion trading between June and September 2010. Specifically, Staff alleges that the individuals (on behalf of Coaltrain) planned and executed large volumes of PJM Up-To Congestion transactions designed to falsely appear to be spread trades but that were in fact a vehicle to collect "Marginal Loss Surplus Allocation" payments from PJM. Staff further alleges that Jones, Sheehan, and their agents (on behalf of Coaltrain) violated the FERC's Market Behavior Rules by making false statements and omitting material information in responding to deposition questions and data requests during the investigation.

Etracom/M. Rosenberg. On July 27, 2015, the FERC issued a notice that OE has preliminarily determined that Etracom LLC ("Etracom") and Michael Rosenberg violated the FERC's Anti-Manipulation Rule by engaging in manipulative virtual trading at the New Melones Intertie in the CAISO footprint during May 2011. Enforcement has preliminarily determined that Etracom's trades were intended to artificially lower the day-ahead LMP to benefit Etracom's congestion revenue rights positions sourced at the same location. During the period in question, Rosenberg was Etracom's principal trader and majority owner.

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.[88] NoVs are designed to increase the transparency of Staff's

[88] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

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.

- **FERC Audit of ISO-NE (PA16-6)**

On November 24, 2015, the FERC informed ISO-NE that it will evaluate ISO-NE's compliance with: (1) the transmission provider obligations described in the Tariff, (2) *Order 1000* as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 C.F.R. Part 125. The FERC indicated that the audit will cover the period July 10, 2013 through the present.

XII. Misc. - Administrative & Rulemaking Proceedings

- **RTO/ISO Common Metrics Report (AD14-15)**

On October 30, 2015, the nation's six RTO/ISOs submitted a report in response to the FERC's "Request for Information on Common Performance Metrics for RTOs and ISOs and Utilities Outside RTO and ISO Regions" issued August 17, 2015 in this proceeding. The 589-page October 30 Report includes discussion and data on both the 30 Common Metrics as well as the "Other Metrics Specific to ISO and RTO Performance" identified in Staff 's August 26, 2014 "Common Metrics Report". The Report has not been noticed for public comment.

- **Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)**

On November 20, 2015, the FERC directed each RTO/ISO to publicly provide information related to certain price formation issues.[89] Specifically, the FERC asked for information regarding five price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC direct each RTO/ISO to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions contained herein on or before February 3, 2016. Following the submission of the RTOs'/ISOs' reports, the FERC will allow for public comment. The FERC also indicated it would use the reports and comments to determine what further action is appropriate.

- **Enforcement Annual Report (AD07-13-009)**

On November 19, 2015, the FERC issued its Annual Enforcement Report. The report provides additional transparency and guidance for regulated entities and the public. Highlights include summaries of activities undertaken by the Office of Enforcement's investigations, audits and accounting, market oversight, and analytics and surveillance divisions. In 2016, the Office Enforcement will continue to target fraud and manipulation, serious violations of mandatory Reliability Standards, anticompetitive conduct, and conduct that threatens the transparency of regulated markets. The Report is available at http://ferc.gov/enforcement/enforce-res.asp.

- **NOPR: Reactive Power Requirements for Wind Generators (RM16-1)**

On November 19, the FERC issued a NOPR proposing to eliminate the exemptions for wind generators from the requirement to provide reactive power.[90] As a result, all newly interconnecting generators, and all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests, would be required to provide reactive power. To implement this requirement, the

[89] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 (Nov. 20, 2015).

[90] *Reactive Power Requirements for Non-Synchronous Generation*, 153 FERC ¶ 61,175 (Nov. 19, 2015).

FERC proposes to revise the *pro forma* LGIA, Appendix G to the *pro forma* LGIA, and the *pro forma* SGIA. Comments on this NOPR are due on or before January 25, 2016.[91]

- **NOPR: Price Formation Fixes - Settlement Intervals/Shortage Pricing (RM15-24)**

On September 17, the FERC issued a NOPR proposing to revise its regulations to require that each RTO/ISO (i) settle (a) energy transactions in its real-time markets at the same time interval it dispatches energy and (b) operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (ii) trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.[92] The FERC sated that adopting these reforms would align prices with resource dispatch instructions and operating needs, providing appropriate incentives for resource performance. The *Settlement Intervals/Shortage Pricing NOPR* was discussed at the October 7-9 Markets Committee meeting. Comments on this NOPR were due on or before November 30, 2015.[93] Nearly 50 sets of comments were filed, including comments by NEPOOL (summarizing the status of New England's consideration of pricing reforms like those identified in the NOPR and urging that FERC action on the NOPR, and any final rule, be sufficiently flexible in implementation schedule and details to permit final approval and implementation of New England's solutions, which are planned to be filed in the first half of 2016 and implemented in 2017), ISO-NE, Potomac Economics (ISO-NE EMM), APPA/NRECA, EEI, EPSA, Direct Energy, Dominion, Entergy, ESA, Exelon, IRC, NEI, Public Interest Organizations, and PSEG. This matter is pending before the FERC.

- **NOPR: Connected Entity Data Collection (RM15-23)**

The FERC issued a NOPR that would dramatically expand the corporate and relationship structure information that all Market Participants will be required to share with the ISO as a condition to their participation and that the ISO would be required to share with the FERC.[94] The FERC proposes to require that all ISO/RTO market participants report all of the their "Connected Entities," which is a newly defined term that is much broader than, and is intended to replace, "Affiliate" as defined in and administered under the ISO Tariff. The rule would multiply by several factors the amount of information required to be reported, by including reporting of certain employee and contractual relationships, and of debt/profitability arrangements. The NOPR proposes additional registration and compliance requirements for each market participant and RTO/ISO. The FERC explains in the NOPR that this additional data collection will improve the information that it has for detecting market manipulation, which is a FERC enforcement priority. A more detailed summary of the *Connected Entity Data Collection NOPR* was distributed with the additional materials for the October 2 meeting.

Dec 8 Technical Conference. Pursuant to a request submitted by a number of market participants, and supported by a number of trade groups and individual market participants, the FERC scheduled a technical conference for December 8 and postponed the due date for comments until 45 days following the technical conference, or January 22, 2016. The technical conference will be held at the FERC's headquarters between 10:00 am and 1:00 pm in the Commission Meeting Room and led by Commission staff (and may be attended by one or more Commissioners). For those not attending in person, the technical conference will be webcast. A supplemental notice issued on November 30 sets out the proposed agenda for the technical conference. In order to advance the discussion, NEPOOL filed its comments on the NOPR on December 1 (consistent with the outline approved at the November 6 Participants Committee meeting). Since the last Report, comments were also filed by Public Citizen. A summary of the December 8 technical conference will be included in the next Report.

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[91] The *Reactive Power Requirements for Non-Synchronous Generation NOPR* was published in the *Fed. Reg.* on Nov. 25, 2015 (Vol. 80, No. 227) pp. 73,683-73,689.

[92] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,218 (Sep. 17, 2015) ("*Settlement Intervals/Shortage Pricing NOPR*").

[93] The *Settlement Intervals/Shortage Pricing NOPR* was published in the *Fed. Reg.* on Sep. 29, 2015 (Vol. 80, No. 188) pp. 58,393-58,405.

[94] *Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,219 (Sep. 17, 2015) ("*Connected Entity Data Collection NOPR*").

- **AWEA Petition for LGIA/LGIP Rulemaking (RM15-21)**

On June 19, the American Wind Energy Association ("AWEA") petitioned the FERC to conduct a rulemaking to revise provisions of the FERC's *pro forma* Large Generator Interconnection Procedures ("LGIP") and pro forma Large Generator Interconnection Agreement ("LGIA"). AWEA states that various aspects of the LGIP and LGIA are out of date in comparison to current market conditions and do not ensure that the generation interconnection process is just, reasonable, and not unduly discriminatory or preferential. AWEA indicated that the rulemaking would address reforms to improve (i) certainty in the study and restudy process, (ii) transparency in the interconnection process, (iii) certainty of network upgrade costs, and accountability in the interconnection process. Comments in response to this petition were due on or before September 8, 2015. More than 30 sets of comments were filed, including by ISO-NE, NESCOE, ISO/RTO Council ("IRC"), APPA/NRECA/Large Public Power Council, EEI, EPSA, NextEra, NRG, and PSEG. Reply comments were filed by AWEA and SunEdison. This matter is pending before the FERC.

- ***Order 812*: Revisions to Public Utility Filing Requirements (RM15-3)**

On July 16, the FERC issued *Order 812*[95] revising its regulation to eliminate the requirement for (i) RTOs/ISOs and EWGs to submit FERC-566 (Annual Report of a Utility's 20 Largest Customers), (ii) for public utilities that have not made any reportable sales under FERC-566 in any of the three preceding years to submit a FERC-566, and (iii) public utilities, when submitting FERC-566, to identify individual residential customers by name and address. The *Order 812* changes became effective October 6, 2015.[96] On August 17, Dominion Resources Services, Inc. ("Dominion") requested clarification and/or rehearing of *Order 812* (seeking clarification that an entity that is both an EWG and QF is not required to file a FERC-566, or rehearing if not so clarified). On November 19, the FERC granted the requested clarification, clarifying "that an entity that is an EWG/QF is exempt from the FERC-566 filing requirement, for the same reasons that an EWG standing alone is exempt from the FERC-566 filing requirement."[97] This proceeding is now concluded.

- ***Order 819*: Third-Party Provision of Primary Frequency Response Service (RM15-2)**

On November 20, the FERC issued a Final Rule permitting the sale of primary frequency response service at market-based rates by sellers with market-based rate authority.[98] Order 819 expands upon the FERC's earlier pronouncement in *Order 784*, which permitted sellers to sell other ancillary services, including imbalance and operating reserve services, at market-based rates. In Order 784, the FERC limited the ability of sellers to make similar market-based rate sales of reactive supply and voltage control service, and regulation and frequency response service, to only certain transactions if certain circumstances are met. Following the issuance of Order No. 784, the FERC held a technical conference in an effort to gather additional information regarding the provision of reactive supply and voltage control service, and regulation and frequency response service at market-based rates. As a result of the information gathered, the FERC issued a proposed rule that differentiated between regulation service and primary frequency response service and also proposed to allow sales of primary frequency response service at market-based rates.

Order 819 found that existing market power screens for sales of energy and capacity are sufficient to demonstrate a lack of market power for sales of primary frequency response, and therefore permits entities granted market-based rate authority to make such sales at market-based rates. The FERC defined "primary frequency response service" as a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over. The FERC also addressed certain other issues regarding the provision of primary frequency response service, including, among other things, a determination that a transmission reservation and schedule is not necessarily required to provide

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[95] *Revisions to Public Util. Filing Reqs.*, Order No. 812, 152 FERC ¶ 61,032 (July 16, 2015) ("*Order 812*"), *clarification granted*, 153 FERC ¶ 61,176 (Nov. 19, 2015).

[96] *Order 812* was published in the Fed. Reg. on July 23, 2015 (Vol. 80, No. 141) pp. 43,619-43,625.

[97] *Revisions to Public Util. Filing Reqs*, 153 FERC ¶ 61,176 (Nov. 19, 2015).

[98] *Third-Party Provision of Primary Frequency Response Service*, Order No. 819, 153 FERC ¶ 61,220 (Nov. 20, 2015) ("*Order 819*").

short duration frequency response service (but may be necessary under certain circumstances; e.g., sales of primary frequency response service from resources in transmission constrained areas).

Order 819 requires sellers to revise the third-party provider ancillary services provision of their market-based rate tariffs in order to make sales of primary frequency response service at market-based rates. However, while *Order 819* is effective as of February 25, 2016,[99] the FERC permits market-based rate sellers to wait to file this tariff revision until the next time they make a market-based rate filing with the FERC, such as a notice of change in status filing or a triennial update. In addition, entities selling primary frequency response service will need to report such sales in their EQRs. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Order 816*: MBR Authorization Refinements (RM14-14)**

As previously reported, the FERC issued *Order 816 o*n October 16, 2015.[100] *Order 816* represents another step in the FERC's efforts to modify, clarify and streamline certain aspects of its market-based rate ("MBR") program. The *Order 816* revisions are intended to both increase transparency and refine existing filing requirements. By way of example, *Order 816:*

- requires electronic submissions of asset appendices in MBR filings to be searchable and sortable, and eliminates the requirement to report behind-the-meter generation in asset appendices
- requires MBR sellers to report all long-term firm purchases of capacity and energy that have associated long-term firm transmission (thereby providing a more accurate measure of a seller's generation resources)
- eliminates MBR sellers' requirement to file quarterly land acquisition information for new generation sites
- reduces the number of "notice of change in status" filings by establishing a new threshold for reporting new affiliations and redefines the default relevant geographic market for an independent power producer with generation capacity located in a generation-only balancing authority area
- provides clarification on issues including capacity ratings and simultaneous transmission import limit (SIL) studies

Order 816 will become effective January 28, 2016.[101] Requests for clarification and/or rehearing of *Order 816* were filed by EDF Renewables, EEI, EPSA, Invenergy, NextEra, Southern Company, TAPS, SoCal Edison, and the National Hydropower Association. These requests are pending before the FERC, with FERC action required on or before December 14, 2015, or the requests will be deemed denied.

- ***Order 771*: Availability of e-Tag Information to FERC Staff (RM11-12)**

On November 19, the FERC denied rehearing and addressed the requests for clarification of the portions of *Order 771* that had not been addressed in Order *771-A.*[102] Specifically, *Order 771-B* denied rehearing requested by NRECA (finding without merit the arguments that the FERC lacked authority to promulgate the regulations that it adopted in *Order 771*) and clarified certain issues. As previously reported, *Order 771*,[103] issued December 20, 2012, 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.

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[99] *Order 819* was published in the Fed. Reg. on Nov. 27, 2015 (Vol. 80, No. 228) pp. 73,965-73,977.

[100] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Srvcs. by Public Utils.*, 153 FERC ¶ 61,065 (Oct. 16, 2015) ("*Order 816*").

[101] *Order 816* was published in the *Fed. Reg.* on Oct. 30, 2015 (Vol. 80, No. 210) pp. 67,056-67,123.

[102] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771-B, 153 FERC ¶ 61,177 (Nov. 19, 2015) ("*Order 771-B*").

[103] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771, 141 FERC ¶ 61,235 (Dec. 20, 2012) ("*Order 771*"), *order on reh'g and clarif.*, 142 FERC ¶ 61,181 (2013), *reh'g denied and clarif. granted*, 153 FERC ¶ 61,177 (2015).

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.[104] 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*.[105] *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*.[106] As noted above, the FERC issued on November 19 *Order 771-B*, which addressed remaining issues raised on rehearing and clarification. Unless Order 771-B is challenged, this proceeding will be concluded.

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 Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19)**

On September 18, 2014, Commissioner Moeller convened a meeting to discuss issues related to how transactions are conducted on the natural gas system and potential transactional improvements to address the needs of electric generators for natural gas. The meeting included representatives/speakers from various sectors of the natural gas and electric industries (load, suppliers, marketers, exchanges, gas associations, and ISOs) and environmental interests. Representatives from NYISO and PJM were among the speakers on the electric side (ISO-NE was not present). A summary of that meeting is posted on the Litigation Updates & Reports webpage (http://nepool.com/uploads/Lit_Supp_AD14-19_20140918_Mtg_Summary.pdf). Written comments on issues discussed at the meeting, limited to 5 pages, were due on or before October 1, 2014. Comments were filed by more than 30 parties. There was no published activity in this proceeding since the last Report.

- ***Order 809*: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On April 16, 2015, the FERC issued *Order 809*,[107] which changed the nationwide Timely Nomination Cycle deadline for scheduling natural gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m.

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[104] *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

[105] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (Mar. 8, 2013) ("*Order 771-A*").

[106] *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.

[107] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, 150 FERC ¶ 61,049 (Apr. 16, 2015) ("*Order 809*").

CCT, and revised the intraday nomination timeline to add an additional intraday scheduling opportunity during the gas operating day (Gas Day). *Order 809* also modified the scheduling practices used by interstate pipelines to schedule natural gas transportation service, and provided additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts. *Order 809* DID NOT change the start time of the nationwide Gas Day (which remains 9:00 a.m. CCT), as had been proposed in the underlying NOPR.[108] *Order 809* established an implementation date of April 1, 2016.[109] On July 23, in response to *Order 809*, ISO-NE described why changes to the time at which the results of the Day-Ahead Energy Market and RAA process are posted were not necessary in response to the FERC's rulemaking. Comments on the ISO-NE's filing were due on or before August 18, 2015, and no party submitted adverse comments in response to ISO-NE's filing (ISO-NE's response was filed in EL14-23; *see* Section I above).

Requests for rehearing and/or clarification of *Order 809* were filed by Desert Southwest Pipeline Stakeholders and the American Gas Association. On May 19, 2015, the Natural Gas Council asked the FERC to defer NAESB consideration of confirmation process improvements until "after the two industries have had sufficient time to implement and operate reliably under both the new gas scheduling timeline and changes to RTO/ISO dispatch schedules to conform with the newly-approved gas scheduling timeline." On September 17, 2015, the FERC issued an Order on Rehearing denying a request from a group of utilities and state regulators from Southwest states for rehearing of *Order No. 809*.[110] The Commission recognized the time commitments in implementing the revised nomination timeline, and requested that the natural gas and electric industries, through NAESB, begin considering the development of standards related to faster, computerized scheduling and file such standards or a report on the development of such standards with the Commission by October 17, 2016.

On May 28, 2015, the American Gas Association, the American Public Gas Association, and the Interstate Natural Gas Association of America (collectively, the Associations) filed a request for the Commission to clarify the manner in which all pipelines should implement the standards on April 1, 2016, as well as requested clarification relating to interpretations of recall rights under existing capacity release contracts in light of the transition from two to three intraday nomination cycles. On July 31, 2015, the FERC issued an Order on Request for Clarification and Notice of Comment Procedures.[111] The FERC indicated that it recognized the value in establishing a default interpretation of capacity release contractual recall provisions to assist parties in navigating the transition between the two intraday and three intraday nomination schedules. The FERC explained that the new day-ahead nomination timelines will apply as of March 31, 2016, for those nominations that will become effective April 1, 2016. Furthermore, with respect to capacity releases, the new biddable release schedule will start at 9:00 a.m. CCT on March 31, 2016, for all releases with contracts to be effective on March 31, 2016, April 1, 2016, or thereafter. Non-biddable releases effective on March 31, 2016 will follow the existing posting schedule for the Intraday 1 and Intraday 2 Nomination Cycles, and will follow the new day-ahead nomination schedule for the Timely and Evening Nomination Cycles.

In response to comments received in response to its July 31 Order, the FERC issued an order on October 15, 2015[112] in which it provided default interpretations to apply to the intraday recall rights associated with capacity release transactions that spanned the implementation date of April 1, 2016. The interpretations are intended to assist parties to capacity release transactions straddling April 1, 2016 in agreeing in advance to contractual recall rights, as such rights are necessarily affected by whether there are three or two intraday

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[108] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

[109] *Order 809* was published in the *Fed. Reg.* on Apr. 24, 2015 (Vol. 80, No. 79) pp. 23,198-23,227.

[110] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, 152 FERC ¶ 61,049 (Apr. 24, 2015), *order on reh'g*, 152 FERC ¶ 61,212 (Sept. 17, 2015).

[111] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 152 FERC ¶ 61,095 (July 31, 2015).

[112] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 153 FERC ¶ 61,049 (Oct. 15, 2015), "Order Establishing Default Interpretations for Capacity Release Contracts".

nomination schedules. Moreover, the FERC also directed releasing shippers to notify the applicable interstate pipeline and the replacement shippers by November 13, 2015 if the parties do not agree on alternative recall rights, and to specify what the releasing shipper believes should be the alternative recall rights.

- **Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442)**

Similar to the ISO/RTO 206 Order in EL14-22 et al. (*see* Section I above), the FERC also instituted a proceeding under Section 5 of the Natural Gas Act to examine whether interstate natural gas pipelines are providing notice of offers to purchase released pipeline capacity in accordance with section 284.8(d) of the Commission's regulations.[113] On or before May 19, natural gas pipelines were required to either revise their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrate that they are in full Compliance with FERC regulations.[114] The FERC also requested that NAESB develop business practice and communication standards specifying: (1) the information required for requests to acquire capacity; (2) the methods by which such information is to be exchanged; and (3) the location of the information on a pipeline's website. The Show Cause Order required each pipeline to explain in its Compliance filing how it will fully comply with section 284.8(d) until NAESB develops, and the FERC implements, the requested standards, including how the pipeline will provide shippers the ability to post offers to purchase capacity on the Informational Posting section of its Internet website.

In total, the FERC received, and addressed in one omnibus order, 157 Compliance filings.[115] Of the 157 filings, 64 pipelines revised their respective tariffs to provide for the posting of offers to purchase released capacity in a manner that complies with section 284.8(d), and 23 pipelines demonstrated that their tariffs already comply with that section. The FERC found that, and identified in its omnibus order on the Compliance filings the, 69 Compliance filings that did not appear to be in full Compliance with that section, and directed further Compliance filings from those companies as described in the omnibus order.

- **Rice Energy Marketing, Order on Petition for Declaratory Order (RP15-1089)**

On October 15, 2015, the FERC issued a Declaratory Order in response to a petition filed by Rice Energy, a producer, clarifying the extent to which releases of natural gas pipeline capacity to asset managers are exempt from FERC's prohibition on buy/sell transactions. The FERC explained that the exemption applies to volumes of gas purchased from a releasing shipper in a "supply asset management agreement" (supply AMA) as well as a "delivery AMA," thereby clarifying that the two types of AMAs are equivalent exemptions from the prohibition on buy/sell transactions.

Under the FERC's regulations, shippers must conduct capacity release transactions through the pipeline consistent with FERC-prescribed posting and bidding requirements. To ensure that capacity holders and persons wishing to acquire capacity did not circumvent those requirements, the FERC established several safeguards, including the requirement that a shipper must have title to the gas transported in the shipper's capacity. Another safeguard is the prohibition on buy/sell transactions whereby a shipper, e.g., a local distribution company or "LDC," purchases gas in the production area from an end-user and uses its capacity to transport the gas and sell the gas to the end-user at the delivery point on its system.

However, in Order No. 712, the FERC exempted AMAs from the competitive bidding requirements of FERC's regulations, the prohibition against tying a release to an extraneous condition, and, at least to some degree, the prohibition on buy/sell transactions. An AMA is a contractual relationship by which a party, an asset manager, agrees to manage gas supply, delivery arrangements, and storage as well as transportation, for another party. Under an AMA, a holder of firm transportation capacity releases a portion or all of its capacity to the asset manager. The capacity holder may also assign gas production and sales contracts to the asset manager.

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[113] *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

[114] *Id.* at P 6.

[115] *See BR Pipeline Co. et al.*, 149 FERC ¶ 61,031 (Oct. 16, 2014).

The Declaratory Order effectively allows a releasing shipper in a supply AMA to use an asset manager solely to manage the releasing shippers' capacity, while continuing to market its own gas. By entering into a buy/sell transaction, producers and marketers can market their own gas and avail themselves of the benefits of an AMA without revealing sensitive competitive information to a competing marketer acting as an asset manager.

- ***Opinion No. 538*: ANR Storage Company, Order on Initial Decision (RP12-479)**

In what it described as "the first fully-litigated proceeding where a gas storage provider has sought market-based rate authority," the FERC, on October 15, 2015, upheld a January 2014 Initial Decision in which a FERC Presiding Judge (ALJ) denied an application for market-based rate authorization by a natural gas storage provider that previously charged cost-based rates for its services. As the first case of its kind, the FERC provided clarity to its policies and procedures for market-based rate applications from gas storage providers, and also described how gas storage providers can meet the evidentiary burden to demonstrate that they lack significant market power. While reversing the ALJ on certain discrete issues (such as the Initial Decision's finding that market-based rate applicants are required to meet their evidentiary burden solely through direct testimony), the FERC ultimately agreed with the ALJ that the applicant (ANR Storage) "has not met its evidentiary burden to show it lacks significant market power in the relevant markets."[116] Requests for rehearing of *ANR Order* were filed by ANR and the Joint Intervenor Group.[117] These requests are pending before the FERC, with FERC action required on or before December 14, 2015, or the requests will be deemed denied.

- **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.

BP (IN13-15). On August 13, Judge Cintron issued her Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations and section 4A of the Natural Gas Act.[118] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. Judge Cintron's Initial Decision found that:

- There were at least 48 violations on 49 days;
- BP's manipulation resulted in financial losses of $1,375,482 to $1,927,728 on the next-day natural gas markets at Houston Ship Channel (HSC) and Katy during the Investigative Period;
- the violation was less than five years after a prior FERC adjudication and adjudications of similar misconduct by the CFTC and DOJ (warranting a 2 point increase in BP's culpability score);
- BP's conduct contravened the terms of a permanent injunction with the CFTC (warranting a 2 point increase in BP's culpability score);
- BP did not have an effective Compliance program; and
- the BP Texas team's gross profits from the manipulation were between $233,330 and $316,170 and net profits between $165,749 and $248,589.

[116] *ANR Storage Co.*, 153 FERC ¶ 61,052 (Oct. 15, 2015) ("*ANR Order*"), *reh'g requested*.

[117] "Joint Intervenor Group" is comprised of the following: the Canadian Association of Petroleum Producers ("CAPP"), Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin (jointly, "NSP"), Tenaska Gas Storage, LLC ("Tenaska"), and BP Canada Energy Marketing Corp., ("BP Canada").

[118] *BP America Inc., et al.*, 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

Judge Cintron also certified the *BP Initial Decision* and the record to the Commission on August 13, 2015. BP filed its Brief on Exceptions on September 14, 2015, and Enforcement Staff filed its Brief Opposing Exceptions on October 5, 2015. This matter is currently pending before the FERC.

Staff Notice of Alleged Violation: Total Gas & Power, North America, Inc. On September 21, 2015, the FERC issued a notice that Staff has preliminarily determined that Total Gas & Power, North America, Inc. ("TGPNA") and its West Desk traders and supervisors Therese Nguyen and Aaron Hall, violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule, by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleges that the scheme involved making largely uneconomic trades for physical natural gas during bidweek designed to move indexed market prices in a way that benefited the company's related positions. Staff alleges that the West Desk implemented the bidweek scheme on at least 38 occasions during the period of interest and that Therese Nguyen and Aaron Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently before the FERC:
  - ***Algonquin Incremental Market Project (AIM Project) (CP14-96)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate Feb. 28, 2014
    - 342,000 dekatherms/day (Dth/d) of firm capacity to NY, CT, RI and MA.
    - 37.6 miles of take-up, loop and lateral pipeline facilities in NY, CT, and MA and system modifications in NY, CT and RI. The system upgrades would also require the removal of some facilities.
    - 10 firm shippers: Yankee Gas, NSTAR, Connecticut Natural Gas, Southern Connecticut, Narragansett Electric, Colonial Gas, Boston Gas, Bay State, Norwich Public Utilities, and Middleborough Gas and Electric (eight LDCs and two municipal utilities).
    - Final Staff-prepared Environmental Impact Statement (EIS) issued Jan. 23, 2015.
    - Certificate of public convenience and necessity granted Mar. 3, 2015.[119]
    - Construction began May 2015.
    - In-service: Nov. 2016 (anticipated).
  - ***Atlantic Bridge Project (CP16-9)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
  - ***Connecticut Expansion Project (CP14-529)***
    - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
    - 72,100 Dth/d of firm capacity.

[119] Order Issuing Certificate and Approving Abandonment, *Algonquin Gas Transmission LLC*, 150 FERC ¶ 61,163 (Mar. 3, 2015), *reh'g requested*.

- 13.26 miles of three looping segments and facility upgrades/modifications in NY, MA and CT.
- Three firm shippers: Connecticut Natural Gas, Southern Connecticut Gas, and Yankee Gas.
- Notice of Schedule issued Sept. 1 with FERC EA to be issued Oct. 23 and 90-day Federal Authorization Decision Deadline set at Jan. 21, 2016.
- FERC Staff-prepared Environmental Assessment (EA) issued on Oct. 23, 2015, as well as contemporaneous notice soliciting comments on or before November 23, 2015.
- Construction expected to begin Winter/Spring 2016.
- In-service: Nov 2016 (anticipated).

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d of firm capacity from Susquehanna County, PA through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - New 122-mile interstate pipeline.
  - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - Final EIS completed on Oct 24, 2014.
  - Certificates of public convenience and necessity granted Dec 2, 2014;
  - Construction expected to begin Dec. 2015 (after final Federal Authorizations).

- ***Salem Lateral Project (CP14-522)***
  - Algonquin Gas Transmission filed application Jul 10, 2013.
  - 115,000 Dth/d of firm capacity.
  - 1.2 miles of pipeline to 630 MW Salem Harbor Station and other Salem, MA facilities.
  - Footprint Power sole firm customer.
  - FERC Staff-prepared EA issued Dec 2, 2014.
  - Certificate of public convenience and necessity granted May 14, 2015.[120]
  - Construction began in May 2015.
  - In-Service: fourth quarter 2015 (anticipated).

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report.

[120] Order Issuing Certificate, *Algonquin Gas Transmission LLC*, 151 FERC ¶ 61,118 (May 14, 2015).

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). 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).

- **Base ROE Complaints (2012 and 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[121]
  Appellants: New England Transmission Owners

On July 13, 2015, the TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings. On July 16, the Court issued a scheduling order directing, among other things, a statement of issues and procedural motions to be filed by August 17 and dispositive motions to be filed by August 31; briefing was deferred until further order of the court. However, on August 14, 2015, NETOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted NETOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. On November 18, the parties filed their first 90-day status report, indicating, ultimately, that the proceedings upon which the NETOs based their request for abeyance of this appeal remain ongoing.

- **Order 1000 Compliance Filings (15-1139, 15-1141**) (consolidated)**
  Underlying FERC Proceedings: ER13-193; ER13-196[122]
  Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, *et al*.

On May 15, 2015, NETOs[123] and NESCOE, *et al*., filed a petition for review of the FERC's orders in the *Order 1000* Compliance Filing proceeding. On June 15, the parties filed a joint statement of issues and unopposed motion regarding briefing format. On June 18, a Joint Statement of issues and docketing statement was filed. On July 2, the Court granted all motions to intervene. On November 6, 2015, the court issued an order setting the following briefing schedule: Jan. 11, 2016 - Joint Brief for Petitioners in No. 15-1139 and Joint Brief for Petitioners in No. 15-1141; Mar. 11, 2016 - Brief for Respondent; Apr. 1, 2016 - Brief for Intervenors Supporting Respondent in No. 15-1139 and Brief for Intervenors Supporting Respondent in No. 15-1141; Apr. 22, 2016 - Joint Reply Brief in No. 15-1139 and Joint Reply Brief in No. 15-1141; May 13, 2016 - Deferred Appendix; May 20, 2016 - Final Briefs. The Court noted that parties would be notified separately of the oral argument date and composition of the merits panel.

- **Base ROE Complaint (2011) (15-1118, 15-1119, 15-1121**) (consolidated)**
  Underlying FERC Proceedings: EL11-66[124]
  Appellants: NETOs

On April 30, 2015, NETOs filed a petition for review of the FERC's orders in the 2011 Base ROE Complaint Proceeding. Motions for leave to intervene have been filed by NEPOOL,EMCOS,[125] NJ Division of

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[121] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[122] 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

[123] "NETOs" are Emera Maine; Central Maine Power Co., National Grid; New Hampshire Transmission ("NHT"), Eversource (on behalf of its electric utility company affiliates CL&P, WMECO, PSNH, and NSTAR), UI, and Vermont Transco.

[124] 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

[125] "EMCOS" are Taunton, Reading, Hingham, and Braintree.

Rate Counsel, NHEC, MMWEC, CT PURA, CT OCC, CT AG, NJ BPU, Delaware PSC, and Coalition of MISO Transmission Customers. The Court granted all motions to intervene on June 23. On August 10, Petitioners filed an unopposed proposed briefing format and schedule. On October 6, 2015, the court issued an order setting the following briefing schedule: Dec. 7, 2015 - brief(s) for Complainants/EMCOS on the issue of the ROE being too high and Joint Brief for NETOs on the issues of the ROE being too low and the modification of incentive adders; December 14 - Joint Brief for Non-New England Intervenors on the issue of the ROE being too high. February 12, 2016 – FERC's brief; March 4 - Joint Intervenor Brief for Complainant, EMCOS, and Non-New England Intervenors on the issues of the ROE being too low and modification of incentive adders and Joint Intervenor Brief for NETOs on the issue of the ROE being too high; March 25 - Reply Brief(s) for Complainants/EMCOS and Joint Reply Brief for NETOs; April 15 - Deferred Appendix; April 26, 2016 - Final Briefs. Since the last Report, the FERC filed a Supplement to the Certified Index of the Record (adding documents it believes are necessary to complete the record in the proceeding).

- **FCM Administrative Pricing Rules Complaint (15-1071**)**
  Underlying FERC Proceedings: EL14-7[126]
  Appellants: NEPGA

On March 31, 2015, NEPGA filed a petition for review of the FERC's orders on NEPGA's FCM Administrative Pricing Rules Complaint. A Docketing Statement Form, Statement of Issues to be Raised, and Petitioners' Appearances were filed on April 23, 2015. Also on April 23, 2015, NEPGA requested that the case be held in abeyance pending the FERC's issuance of an order on rehearing of its initial order in Exelon Corporation v. ISO New England Inc. (EL15-23). Motions for leave to intervene have been filed by NEPOOL, CT PURA, CT OCC, NESCOE, NECPUC, NHEC, and PSEG. On May 22, the Court granted all motions to intervene and NEPGA's motion to hold the case in abeyance pending a decision in EL15-23. Motions to govern future proceedings are due 30 days from the completion of the FERC proceedings in EL15-23. NEPGA was directed to, and did, file an abeyance status report on or before August 20, 2015. In its August 20 report, NEPGA indicated that the FERC had not taken final action in EL15-23 and requested the Court continue to hold the case in abeyance. NEPGA filed a second abeyance status report on November 18, again requesting that the Court continue to hold this case in abeyance.

- **Demand Curve Changes (15-1070**)**
  Underlying FERC Proceedings: ER14-1639[127]
  Appellants: NextEra, NRG and PSEG

On March 30, 2015, NextEra, NRG and PSEG filed a petition for review of the FERC's orders in the Demand Curve Changes proceedings. Motions for leave to intervene have been filed by NEPOOL, the ISO, CT PURA, NHEC, CPV, Entergy, and NESCOE. A Docketing Statement Form, Statement of Issues to be Raised, and Appearances were filed by Petitioners on April 30, 2015. The Petitioners' Non-Binding Statement of Issues laid out various challenges to the renewables exemption that was approved as part of the FERC's Demand Curve Orders. On May 28, the Court granted all filed motions to intervene and ordered intervenors to show by June 29 cause why they should not be limited to one joint brief in support of the FERC. On June 26, CT PURA filed a statement requesting permission from the Court to file its own brief in support of the FERC. Also on June 26, NESCOE, CPV and NHEC filed a statement regarding briefing format. On August 5, the Court issued a briefing schedule, which calls for brief for Petitioners by October 5; brief for Intervenor Supporting Petitioners by October 20; brief for Respondent by December 4; brief of Intervenor CT PURA Supporting Respondent by December 21; and brief of other Intervenors Supporting Respondent by December 21, 2015.

On October 5, 2015, the Petitioners submitted their brief, followed by an Intervenor brief in support filed by Entergy Nuclear Power Marketing, LLC, on October 20, 2015. The Petitioners' brief set forth numerous objections to the FERC's orders approving the renewables exemption, including that FERC's FCA methodology will cause electric generation capacity rates to be unjust, unreasonable and unduly discriminatory, and that the

[126] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[127] 150 FERC ¶ 61,065 (Jan. 30, 2015); delegated letter order (Nov. 13, 2014); 147 FERC ¶ 61,173 (May 30, 2014).

FERC ignored evidence that demonstrated that the exemption would cause significant artificial price discrimination.

On November 20, the FERC requested that the Court remand this case back to the Commission for further proceedings (stating that "review of the opening briefs indicates that further consideration by the Commission is appropriate"). On December 1, the Court granted FERC's unopposed motion, and remanded the case back to the Commission for further proceedings.

- **FCA8 Results (14-1244, 14-1246 (consolidated))**
  Underlying FERC Proceedings: ER14-1409[128]
  Appellants: Public Citizen and CT AG

On November 14, 2014, Public Citizen and the CT AG filed petitions for review of the FERC's action on the FCA8 Results Filing, which became effective by operation of law on September 16, 2014. These proceedings have been consolidated. A Docketing Statement Form and Statement of Issues to be Raised were filed by Petitioners by December 22, 2014. On January 2, 2015, the FERC filed a motion to dismiss the petitions for lack of jurisdiction. The FERC argued that the Court lacks jurisdiction because Petitioners did not challenge a FERC "order" within the meaning of section 313 of the FPA, or "agency action" reviewable under the Administrative Procedures Act. On January 15, EPSA and NEPGA jointly filed a motion supporting the FERC's motion to dismiss. On January 26, Connecticut[129] and Public Citizen opposed the FERC's motion to dismiss. On February 5, the FERC replied to the Public Citizen and CT AG responses. On April 7, the Court ordered that the motion to dismiss be referred to the merits panel and parties were directed to address in their briefs the issues presented in the motion to dismiss rather than incorporate those arguments by reference. On April 9, the FERC filed an unopposed motion for a schedule setting a minimum 60-day briefing interval for the FERC. On April 10, the Court ordered that parties submit proposed formats for the briefing of the consolidated cases by May 11. The parties filed a joint proposed briefing schedule on May 11. On July 1, the Court issued a briefing schedule -- brief for State Petitioners due 9/4/2015; brief for Public Citizen due 9/4/2015; brief for Respondent due 11/3/2015; brief for FERC/Intervenors due 11/18/2015; reply briefs for Petitioners due 12/2/2015; final briefs due 12/23/2015. In accordance with that schedule, briefs of State Petitioners and Public Citizen were filed on September 4, FERC's Respondents brief, on November 3; Intervenor for Respondent Brief by EPSA/HQ US/NRG/NEPGA, on November 18; and Petitioner Reply Briefs by CT OCC/CT PURA/CT AG and Public Citizen, on December 2. Final Briefs are due next, by December 23.

- ***2013/14* Winter *Reliability Program* (14-1104, 14-1105, 14-1103 (consolidated))**
  Underlying FERC Proceedings: ER13-1851[130] **and ER13-2266**[131]
  Appellants: TransCanada and RESA

On June 6, 2014, TransCanada and the Retail Energy Supply Association filed petitions for review of the FERC's orders on the 2013/14 Winter Reliability Program (14-1104 and 14-1105, respectively). Also on June 6, 2014, TransCanada filed a petition for review of FERC's orders on the 2013/14 Winter Reliability Program Bid Results Filings (ER14-1103). On July 3, 2014, these proceedings were consolidated. On July 7, 2014, the FERC requested a minimum of 60 days after Petitioners' opening briefs to file its brief. On July 23, leave to intervene was granted to ISO-NE, NEPGA, PSEG and Essential Power. On September 29, 2014, TransCanada, RESA, FERC, ISO-NE, Essential Power MA, PSEG and NEPGA filed a proposed joint, unopposed briefing format and schedule. A Joint Brief for Petitioners was filed on November 24 (as corrected on December 1). At the FERC's request, the Court ordered that a revised briefing schedule be applied in this case (effectively extending the overall briefing schedule by one month. Briefs for Respondent and Respondent-Intervenors were filed February 13 and March 2, respectively. Petitioners' Joint Reply Brief was filed on March 25; the Deferred Appendix, April 1,

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[128] Notice of Filing Taking Effect by Operation of Law, *ISO New England Inc.*, Docket No. ER14-1409 (Sep. 16, 2014); Notice of Dismissal of Pleadings, *ISO New England Inc.*, Docket No. ER14-1409 (Oct. 24, 2014).

[129] For purposes of this proceeding, "Connecticut" means the CT AG, CT PURA and CT OCC.

[130] 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

[131] 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

2015. Final Briefs were filed on April 15, 2015. Oral argument was held on September 15, 2015 before Judges Tatel, Pillard and Edwards. This matter is pending before the Court.

- **New England's Order *745* Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336[132]
  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 issuance of the mandate in the *Order 745* appeal.

- **Orders 745 and 745-A (FERC v. EPSA, Supreme Court, 14-840 and 14-841)**
  Underlying FERC Proceedings: RM10-17-000[133]
  Appellants: FERC and EnerNOC

On January 15, the Solicitor General of the United States, on behalf of the FERC, filed with the Supreme Court a petition for a writ of certiorari seeking review of the District Court's May 23 Decision.[134] Respondents brief in opposition to that writ, pursuant to an order of the Court extending the time for responses, was filed on March 19. Petitioner's reply was filed on April 7. The Supreme Court granted certiorari on May 4, 2015. On May 27, the Supreme Court granted extensions to file petitioners' briefs to July 9, 2015 and respondents' brief to August 31, 2015. On July 9, briefs were submitted by EnerNOC, FERC, CA PUC, Joint States, and PJM. A number of amicus curiae briefs were submitted on July 16. Since the last Report, amicus curiae briefs were submitted by Midwest Load-Serving Entities and EPSA on August 31; by CES and Dr. Silkman on September 1; by the NC PUC on September 4; and on September 8 by NEI/America's Natural Gas Alliance and Robert L. Borlick, et al. Oral argument was held October 14, 2015.

As previously reported, the DC Circuit vacated *Order 745*[135] in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market" in a 2-1 decision ("Decision") issued on May 23, 2014. The DC Circuit vacated *Order 745* on two separate and independent grounds. First, it held that the FERC does not have jurisdiction to regulate demand response. The Court reasoned that: (i) the states retain exclusive authority to regulate the retail market; (ii) absent an express statutory grant of authority, the FERC cannot regulate areas left to the states; (iii) the FPA provides the FERC with authority over wholesale sales of electricity, but demand response is not such a sale; (iv) the authority of the FERC to regulate wholesale power rates under the FPA cannot be read so broadly as to allow direct regulation of demand response; and (v) demand response, while not necessarily a retail sale, is part of the retail market, involving retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption. Therefore, the Court concluded, the FERC has no authority to directly regulate demand response. "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."

As an alternative and secondary basis for its decision against *Order 745*, the Court concluded that the FERC order was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." The Court found that the FERC failed to reasonably consider and address arguments that *Order 745* will result in over-compensation of demand response resources, resulting in unjust and discriminatory rates. The Court further found that the FERC failed to demonstrate how its proposed pricing construct would result in just

[132] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

[133] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

[134] *EPSA v. FERC*, 753 F.3d 216 (May 23, 2014).

[135] *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

compensation. The Decision and preliminary implications of the Decision were summarized in more detail in the memo included with the supplemental materials circulated and posted for the June 6 meeting.

- **CPV Maryland, LLC v. PPL EnergyPlus et al. (Supreme Court, 14-623)**

A petition for a writ of certiorari in this case was filed on November 26, 2014 and placed on the Supreme Court's docket on November 28, 2014 as No. 14-623. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, and APPA. Respondents (PPL EnergyPlus, LLC, et al.) filed a response on February 11. Petitioner CPV Maryland, LLC replied on February 24. On March 23, the Court invited the Solicitor General to file a brief in the case expressing the views of the United States. Since the last Report, the Solicitor General filed, on September 16, an amicus brief of the United States. On September 29, petitioner CPV Maryland filed a supplemental brief. The case was distributed on September 30 for the Court's October 16, 2015 Conference. The Supreme Court granted certiorari on October 19, 2015. Oral argument is set for one hour and has yet to be scheduled.

As previously reported, on June 2, 2014, the 4th Circuit Court of Appeals affirmed the September 30, 2013 decision of the United States District Court for the District of Maryland[136] which 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.[137] In affirming the District Court decision, the 4th Circuit found the MD PSC Order to be both field[138] and conflict pre-empted.[139]

With respect to field pre-emption, the 4th Circuit stated that a "wealth of case law confirms FERC's exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged."[140] It found the federal scheme (i.e. the PJM Market) "carefully calibrated to protect a host of competing interests" (representing "a comprehensive program of regulation that is quite sensitive to external tampering"),[141] and leaving "no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result." Accordingly, the 4th Circuit concluded that the MD PSC Order was "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction."[142] The MD PSC Order "compromises the integrity of the federal

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[136] *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 ("*District Court Decision*"). The *District Court Decision* was summarized in past Litigation Reports.

[137] *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467; 2014 U.S. App. LEXIS 10155.

[138] "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.

[139] "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."

[140] Slip op. at p. 14.

[141] *Id.* at p. 10.

[142] *Id.* at p. 16.

scheme and intrudes on FERC's jurisdiction" because the MD PSC Order "effectively supplants the rate generated by the auction with an alternative rate preferred by the state." The 4th Circuit rejected arguments that the CfD payments "represented a separate supply-side subsidy implemented entirely outside the federal market."[143] And, even if the presumption against preemption were to apply, the Court found that that it was "overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC."[144]

With respect to conflict pre-emption, the 4th Circuit found that the MD PSC Order "presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted".[145] Preemption was appropriate because of the "extensive and disruptive" impact of the MD PSC Order on matters within federal control (the PJM markets). It found that the MD PSC Order had "the potential to seriously distort the PJM's auction's price signals, thus 'interfer[ing] with the method by which the federal statute (i.e. the PJM Markets) was designed to reach its goals."[146] "Maryland's initiative disrupts [the PJM scheme] by substituting the state's preferred incentive structure for that approved by FERC."[147] "Maryland has sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible."[148]

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. On June 17, 2014, the 4th Circuit stayed the mandate pending the *en banc* ruling on the Petitions. On June 30, 2014, the 4th Circuit denied the petitions for rehearing *en banc*.

- **CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al. (Supreme Court, 14-634, 14-694)**

Petitions for a writ of certiorari in this case were filed on November 26, 2014 and December 10, 2014 and placed on the Supreme Court's docket as Case Nos. 14-634 and 14-694, respectively. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, APPA, AWEA, and the NY PSC. Since the last Report, Respondents (PPL EnergyPlus, LLC, et al.) filed a brief opposing the writ of certiorari on February 11. Petitioners (CPV Power Development, Inc., et al.) replied to that brief on February 20. On March 23, the Court invited the Solicitor General to file a brief in the case expressing the views of the United States. Since the last Report, the Solicitor General filed, on September 16, an amicus brief of the United States. On September 29, petitioner CPV Maryland filed a supplemental brief. The case was distributed on September 30 for the Court's October 16, 2015 Conference.

As previously reported, on September 11, 2014, the 3rd Circuit Court of Appeals affirmed[149] the analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring unconstitutional (and therefore null and void) New Jersey's Long Term Capacity Agreement Pilot Program Act ("LCAPP").[150] In affirming the New Jersey District Court's decision, the 3rd Circuit concluded:

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[143] *Id.* at pp. 18-19.

[144] *Id.* at p. 20. The Court noted the limited scope of its holding, which "is addressed to the specific program at issue" and did not "express an opinion on other state efforts to encourage new generation." *Id.* at p. 21.

[145] *Id.* at p. 27.

[146] *Id.* at p. 23.

[147] *Id.* at p. 24. ("Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.")

[148] *Id.* at p. 25.

[149] *PPL EnergyPlus, LLC v. Hanna*, 977 F.Supp.2d 372 (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, ("*NJ Order*").

[150] *PPL EnergyPlus, LLC v. Hanna*, 766 F.3d 241; 2014 U.S. App. LEXIS 17557 (Sep. 11, 2014).

> LCAPP compels participants in a federally-regulated marketplace to transact capacity at prices other than the price fixed by the marketplace. By legislating capacity prices, New Jersey has intruded into an area reserved exclusively for the federal government. Accordingly, federal statutory and regulatory law preempts and, thereby, invalidates LCAPP and the Standard Offer Capacity Agreements.[151]

No petition for rehearing or rehearing *en banc* was filed on or before September 25, 2014. Accordingly, the mandate was issued on October 3, 2014. As noted above, petitions for *certiorari* to the U.S. Supreme Court were filed and are pending before the Supreme Court.

- **Entergy Nuclear Fitzpatrick, LLC et al v. Zibelman et al (NY PSC Commissioners) (N.D.N.Y. 5:15-cv-00230-DNH-TWD)**

Entergy[152] filed, on February 27, in the United States District Court for the Northern District of New York, a Complaint that seeks a declaratory judgment that the NYPSC Commissioners' order ("Order") approving an agreement to keep NRG's 435 MW Dunkirk facility in the NYISO market, "repowered" as a natural gas-fired (rather than coal-fired) plant (the "Term Sheet")[153] is preempted by the FPA and invalid under the dormant Commerce Clause of the U.S. Constitution. Entergy also seeks a permanent injunction requiring the NYPSC Commissioners to withdraw its Order and/or preventing the NYPSC Commissioners from continuing to treat the Order as valid and binding. This case is noteworthy given the relationship of the issues raised to the Maryland and New Jersey CfD cases summarized above.

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[151] *Id.* slip op. at 31.

[152] Plaintiffs are Entergy Nuclear FitzPatrick, LLC ("FitzPatrick"); Entergy Nuclear Power Marketing, LLC ("ENPM"); and Entergy Nuclear Operations, Inc. ("ENOI").

[153] The Term Sheet provides that, in exchange for Dunkirk's commitment to participate in the NYISO energy and capacity markets through 2025, Dunkirk will receive out-of-market payments of $20.4 million per year from National Grid and a $15 million one-time subsidy from a New York State agency. Entergy asserts that the contract structure will lead Dunkirk to bid below its actual costs in the capacity auction, causing the auction market to "clear" at a lower price than otherwise would have resulted, and resulting in all generators receiving lower capacity revenues than they otherwise would have received.

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2016 Committee Meeting Schedule

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Jan	8	12-13	26	20	21	29	11	5 & 26	6 & 27	28	----	14	----	27	----
Feb	5	9-10	23	16	17 & 18	11	15	----	----	25	2	11	24	24	----
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Aug	5	16 - 17	9 - 10	9 - 10	18	11 & 24	15	30	31	25	----	11	----	31	----
Sep	9	13 - 14	27	20	21	----	12	27	28	22	6	22	----	28	7
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Nov	4	9-10	17	15	16	22	14	29	30	----	1	10	----	30	----
Dec	2	6-7	15	13	14	----	12	----	----	----	----	8	13	28	5

*** Summer Meeting Dates**

Consumer Liaison Group: March 10, June 16, October 13, December 1
NECPUC Symposium: June 5-8
MACRUC: June 19-22
NARUC: Winter Meeting February 14-17; Summer Meeting July 24-27; Annual Meeting November 13-16

EBA Primer & Annual Meeting: June 7-8
EBA Primer & Mid-Year Meeting: Oct 5-6
NECA Annual Energy Conference: May 10-11

Rev 11/13/15