David T. Doot
Secretary

December 26, 2012

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of January 4, 2013 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee **will be held on Friday, January 4, 2013, at 10:00 a.m.** ***at The DoubleTree Hotel Boston/ Westborough, 5400 Computer Drive, Westborough, MA.*** The Participants Committee meeting will be held in the Chandler Ballroom for the purposes set forth on the attached agenda. For your information, this meeting will be recorded, as are all NEPOOL Participants Committee meetings.

2013 NEPOOL Annual Fees FOR PARTICIPANTS WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE: The NEPOOL annual fees will be in the February invoices for all Participants in the Pool as of January 1, 2013. To avoid a Payment Default, the payment for the annual fee must be received by the ISO not later than the second business day paid following issuance of the invoice, or Wednesday, February 13, 2013. Invariably, numerous Participants fail to pay these invoices on time and end up in a Payment Default with additional penalties assessed. As a courtesy, the ISO has sent a reminder and additional payment information directly to Participants who do not typically receive weekly invoices. However, we urge all Participants to anticipate this February invoice and plan accordingly.

Directions to the DoubleTree Hotel are included with this notice. Rooms at the DoubleTree Hotel for the January 4 meeting are available at the rate of $129.00 per night. Those wishing to take advantage of those arrangements should contact Mr. Oliver Knight, Director of Catering at the Westborough DoubleTree directly (508-616-7410 (phone); 508-366-3950 (fax); oliver.knight@hilton.com).

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meetings held on November 9 and December 7, 2012. Preliminary minutes of the November 9 and December 7 meetings, marked to show changes from the drafts previously circulated, are included with this supplemental notice.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To discuss 2013 Business Priorities. Background material will be circulated in advance of the meeting

6. To consider and take action, as appropriate, on proposed changes to the Day-Ahead Energy Market and Reserve Adequacy Assessment timelines. Background material and a draft resolution are included with this supplemental notice.

7. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be circulated in advance of the meeting.

8. To receive reports from committees and subcommittees.

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

PRELIMINARY

A special meeting of the NEPOOL Participants Committee was held via teleconference at 9:30 a.m. on Friday, November 9, 2012. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded.

INFORMATION POLICY CHANGES (GAS PIPELINE INFO SHARING CHANGES)

Mr. Bowie stated that the purpose of the special meeting was to consider proposed revisions to the ISO New England (ISO) Information Policy (Information Policy Changes). He outlined the process for the conduct of this special meeting.

Ms. Allison DiGrande, Chair of the Markets Committee, summarized the ISO's proposed Information Policy Changes, intended to improve gas-electric coordination prior to winter 2012/2013 by allowing the ISO to disclose confidential forecast and Real-Time output of natural gas-fueled generation from New England resources to operating personnel of the interstate natural gas pipeline companies that serve those resources. She reported that the ISO proposed, and the Markets Committee recommended support for, changes to the Information Policy to disclose this confidential information subject to a non-disclosure agreement (NDA) between the ISO and each pipeline company to protect the confidentiality of any information that is disclosed. She explained that the Information Policy Changes recommended by the Markets Committee did not include a form of NDA.

Mr. Doot reminded the Committee that the ISO committed at the November 2, 2012 Participants Committee meeting to file the form of NDA with the FERC for approval, and that the special meeting was scheduled to give parties one more week work together to identify a form that would be satisfactory to all the parties. He explained that representatives of the ISO, the pipelines, and ~~the~~ generators whose information would be shared (affected generators) had since worked together, and the ISO had identified a form of NDA that was reported to be satisfactory to the pipelines, but not to the affected generators. He indicated that, procedurally the Committee could agree if it wished by friendly amendment to modify the Markets Committee-recommended Information Policy Changes to reflect inclusion of the form NDA. He explained that generators' concerns could then be addressed by the Committee through a second motion to amend the ISO-recommended Information Policy Changes. Mr. Doot explained that the ISO had indicated that it would insist on a separate vote on its proposed changes if the generator-proposed amendment passed, and he reported that a 60% vote was required to support changes to the Information Policy.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Information Policy, as recommended by the Markets Committee, and as circulated to this Committee in advance of this meeting, together with those changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

ISO-Proposed Revisions to Markets Committee-Recommended Changes

Mr. Bowie then called on Committee members by Sector to comment on the motion. In response to questions, the motion and the process that preceded the proposal included in the motion were clarified. The Committee then agreed to accept as a friendly amendment the ISO-proposed revisions to the Markets Committee-recommended changes, as reflected in the Attachment A materials circulated to the Committee on November 8.

Continuing discussion of the motion, a Generation Sector representative suggested that no changes to the Information Policy were necessary because the FERC already required generators to provide directly to the pipelines the confidential information that the ISO claimed it wished to share with the pipelines. A Supplier Sector representative, whose Company also had generation in New England, expressed appreciation for all the efforts to address concerns with the Information Policy Changes, which were in ~~his~~her view much improved from the earlier proposal that did not include a form of NDA. However, she stated that the proposal still did not go far enough to protect affected generators, and an amendment would be offered to address remaining concerns/issues. She emphasized the desire of generators to facilitate the information sharing sought by the ISO, but subject only to appropriate protections of their interests given the fact that the information to be shared was confidential, competitively sensitive data.

In response to questions, the ISO confirmed that (i) the NDA would protect confidential information for six months, after which there would be no further protection under the NDA, and (ii) gas pipelines might also provide confidential information to the ISO under the NDA as a result of the Information Policy Changes. The ISO explained that its intent was to balance the understandable interest of generators to preserve the confidentiality of their information with the interest of the pipelines to avoid unlimited risk exposure, all while allowing better information exchange to enhance efforts to ensure reliability of both the gas and electric systems.

NEPGA Amendment to the NDA

The Capital Power representative, on behalf of the New England Power Generators Association (NEPGA), offered a motion to amend the once-amended main motion, to revise Sections 3(b) and 13 of the Non-Disclosure Agreement (NDA): (1) to address the treatment of information following expiration of the confidential period; and (2) to make the affected generators third-party beneficiaries of the NDA, as reflected in the NEPGA Amendment circulated as Attachment B in the November 8 materials. The motion to amend the once-amended main motion was duly made and seconded.

Mr. Bruce Anderson, NEPGA Director, Market & Regulatory Affairs, explained the reasons for proposing the NEPGA Amendment to the NDA. He said generators wanted an outcome that permitted the ISO and the pipelines to share confidential, commercially sensitive information but also to ensure that ~~the~~affected generators ~~whose information was being shared~~ were in a position to protect their commercial interests. He explained his view that, under Massachusetts law, a non-party that was an intended beneficiary of an agreement would have certain rights to enforce that contract as a third-party beneficiary. He stated that the purpose of the NDA was to prevent disclosure of affected generators' commercially sensitive information ~~of affected generators~~, and that those generators were the intended beneficiaries and should be recognized as such. He referred to the fact that the existing NDAs under the Information Policy between the state regulators and the ISO and between educational institutions and the ISO ~~under the Information Policy~~ each provided that all Governance Participants are intended third-party beneficiaries of those NDAs. He argued that affected generators should have the same third-party rights under the contract proposed by the ISO. He urged non-generators to consider the precedent that would be established with respect to third-party beneficiary data protections. Referring to Section 3 of Attachment B relating to the protection period, Mr. Anderson explained that the confidential information may still be commercially valuable and sensitive after six months and generators wanted to maintain some protections. They proposed changes to obligate pipelines if requested to return to the affected generator any written confidential information received ~~if requested~~.

Members then commented, Sector by Sector, on the NEPGA Amendment. In response to questions, the Capital Power representative explained her understanding that, although at least one pipeline had been satisfied with NDA silence as to the third-party beneficiary issue, which would have at least supported an argument by affected generators that such rights were inherent in the agreement, other pipelines had specifically refused to sign an NDA that failed to include language expressly prohibiting third-party rights. As a result, she understood that the pipelines had collectively insisted on the language objectionable to the potentially affected generators. Ms. Gulluni confirmed that the generators' ~~efforts to clarify~~statements clarifying their rights to pursue pipelines for damages in state court if the NDA was breached resulted in the pipelines' unwillingness to remain silent on this topic. She explained that the pipelines had made it clear that they would not sign an NDA that had implied or explicit third-party beneficiary rights for generators, and without execution of an NDA, even with implementation of changes to the Information Policy, the ISO~~-~~ would not be able to share confidential Real-Time and forecast information with the pipelines. Accordingly, the ISO could not ultimately support a form of NDA that was not clear that there were no intended third-party beneficiaries under the NDA.

There was further discussion of the legal and practical significance of the proposed language, of the ISO's proposed language, and of remaining silent on the issue in the NDA. Mr. Anderson reiterated affected generators' concern that if they were not a third-party beneficiary to the contract, they would not have an adequate remedy against a pipeline if the pipeline breached the contract and the affected generator was harmed. Third-party beneficiary rights allowed for a remedy for affected generators in such situations.

Mr. Raymond Hepper, ISO General Counsel, reminded the Committee that the FERC had rules and processes to protect that information and to provide redress. He stressed the importance of those already-~~-~~effective protections and reminded that Committee that the ISO was trying to facilitate information exchange with the pipelines when ~~its~~it perceived a problem between the gas and electric systems without additional fear of lawsuits or litigation. Mr. Anderson responded that FERC remedies might not be as expansive as remedies in state court for breach of the NDA. Others expressed concern as well that the FERC processes may not provide adequate remedies and argued that the generators were not unreasonably seeking to preserve their rights by including a third-party beneficiary right in the form NDA.

A member of the Transmission Sector suggested, as a possible alternative, that there be an explicit commitment that, in the event of a breach by one of the pipelines, the ISO would pursue any and all remedies available to ~~them~~it to prevent that breach from continuing, including seeking injunctive relief as contemplated by Section 4 of the draft NDA.

A Publicly Owned Entity Sector member summarized the Sector's position, particularly in light of the meeting's discussion, that expedited, enhanced consultation between the ISO and the pipelines was desirable and the legitimate commercial concerns raised by the sharing of Market Participant information be similarly addressed on an expedited basis.

In response to questions, the ISO clarified that, if the NEPGA Amendment passed, the pipelines would not sign the NDA and the ISO intended to file ~~an~~a reasonable NDA that the pipelines could sign. NEPOOL counsel clarified that votes on the Information Policy were not *per se* subject to the jump-ball provision of the Participants Agreement.

An End User member acknowledged the importance of addressing the identified reliability issues, but urged protection of the commercial interests implicated by the information sharing. He suggested that a failure to protect confidential information would undermine confidence in the markets, that would in turn undermine the reliability of the system. Thus, adequate protection for confidential information was highly desirable and third party beneficiary language a reasonable line of defense. Another End User member, noting the absence of the pipelines during the discussion, recommended going forward that NEPOOL invite the pipelines to participate in meetings where pipeline interests were involved.

Ms. Heather Hunt, Executive Director of the New England States Committee on Electricity (NESCOE), expressed appreciation on behalf of the states for the efforts of all affected parties in trying to reach a reasonable resolution in the interest of reliability. She emphasized that NESCOE's state members had not taken a formal position but wanted to see the matter resolved in a way intended to support reliability.

In response to members' questions and comments, Mr. Anderson clarified that the reference to "written information" is Section 3 was intended to ensure that confidential information capable of being copied would not be retained following the protection period.

For the ISO, Dr. Chadalavada clarified that the information the ISO wanted to share with a pipeline when the operating system was under stressed conditions and presented reliability concerns to the ISO was information about commitments for dispatch of resources during th~~e~~at time period ~~presenting reliability concerns to the ISO~~. He stressed that the confidential information to be shared would be limited to ISO commitment and dispatch information. He explained that the ISO viewed the issue as an infrastructure issue to be pursued to ensure that load would be served reliably and the integrity of the markets preserved.

Ms. Gulluni said that the ISO expected most of the information ~~to~~would be shared orally and in Real-Time. She opined that the ISO would be administratively burdened and unnecessary costs imposed should it and the pipelines be required to track/maintain records of all information shared~~, monitor it for a year~~ and then delete any written documents created as a result after the confidential period. Addressing the ISO's concern with an NDA that pipelines would not sign, she questioned whether the FERC could or would require the pipelines to sign the NDAs. If they did not sign those agreements, the Information Policy Changes would be meaningless since the NDA must be executed by the ISO and the pipelines in order for the ISO to share the information. Ms. Gulluni stated that, if it would be helpful, the ISO would confirm in the filing letter its intent to enforce the obligations created in the NDA. She also stated the ISO remained convinced that existing federal protections were sufficient to protect the affected generators' information. She concluded by reiterating the ISO's view that it had struck an appropriate balance under the circumstances.

In final comments, Mr. Anderson summarized the purpose and importance to affected generators of the NEPGA Amendment. He emphasized generators' understanding of the challenges faced by the ISO, this winter and going forward, in maintaining reliability, and their willingness and exhaustive efforts to cooperate to that end, but not at the expense of their commercial interests or in the absence of reasonably adequate recourse in case of a breach of confidentiality.

In response to process questions raised, Mr. Doot referred the Committee to the memorandum from NEPOOL Counsel circulated with the meeting materials in advance of the meeting. He explained that, under the Participants Agreement, a change to the Information Policy would be treated for voting purposes the same as a change to the Market Rules, with a 60% vote threshold required for approval. He explained further that the jump ball provisions of Section 11.1.5 of the Participants Agreement addressed alternative Committee Market Rule changes and did not reference Information Policy changes. While there could be an argument that NEPOOL support for an alternative Information Policy proposal could trigger a jump ball filing, unless directed otherwise, NEPOOL counsel did not intend to make that argument in this instance. He explained the standard of review likely to be followed by the FERC if the ISO made a Section 205 filing and the burden of NEPOOL or those challenging such a filing to advocate for alternative changes. He further suggested that it was possible for the FERC to accept an ISO filing as submitted to remain in effect until such time ~~that~~as the Commission ~~can~~could issue a final ruling on the issues/concerns raised, with the understanding that any changes from what was filed would be prospective only. In response to the ISO's concern about the authority of the FERC to order the pipelines to abide by an NDA that included provisions to which the pipelines objected, Mr. Doot concurred that the Federal Power Act might not provide such authority. However, he suggested that any argument seeking such an order could be made pursuant to the Natural Gas Act, where the FERC could be on strong footing ordering such an outcome if the proper findings were made in support of such an order.

The Committee then considered and approved the NEPGA Amendment with a 98.10% Vote in favor (Generation - 17.1%; Transmission - 17.1%; Supplier - 17.1%; Alternative Resources - 14.5%; Publicly Owned Entity - 17.1%; and End User - 15.2%). (See Vote 1 on Attachment 2).

Vote on the Twice-Amended Main Motion

Following motion duly made and seconded, the twice-amended main motion (as amended by the ISO-proposed revisions and the NEPGA Amendments to the NDA) (the "Alternative NDA") was then voted and approved with a 95.73% Vote in favor (Generation - 12.83%;

Transmission - 17.1%; Supplier - 17.1%; Alternative Resources - 14.5%; Publicly Owned Entity - 17.1%; and End User - 17.1%). (See Vote 2 on Attachment 2).

Vote on the Proposal Acceptable to the ISO

At the request of the ISO, and following motion duly made and seconded, the Committee considered the proposal acceptable to the ISO, i.e., the Markets Committee-recommended proposal once-amended by the ISO-proposed revisions accepted by friendly amendment. Members generally expressed appreciation and support for the ISO's efforts but emphasized the importance of NEPOOL's desire to ensure members' rights to careful and appropriate handling of confidential information with the ability of affected members to guard those rights. Members indicated that they could support the ISO's proposal but urged NEPOOL Counsel to advocate vigorously in favor of respecting the rights of members to protection of their confidential data.

Mr. Hepper responded that the ISO recognized both the reliability concern and the importance of the confidentiality issue and planned to present the Information Policy Changes to the FERC in a way that would allow the ISO to share information with the pipelines in the near term while discussions were underway on longer-term arrangements. Mr. Doot explained that NEPOOL approval of two proposals was unusual and that NEPOOL counsel, absent instructions to the contrary, would interpret such results as an indication that NEPOOL ~~can~~could accept either proposal, and that a passing vote would signal a preference for the first version, but a clear signal that one or the other version should be implemented.

Some representatives explained that they would likely abstain in order to signal the importance of the reliability issues. Others indicated that they would vote in favor of the ISO's approach to signal clear support for ensuring reliability, but they preferred the Alternative NDA in order to address the potential commercial issues that were implicated by the proposed communications between the ISO and pipeline operators.

The ~~ISO~~ once-amended ~~motion~~ISO proposal was then voted and ~~approved~~supported with a 81.72% Vote in favor (Generation - 0%; Transmission - 17.1%; Supplier - 17.1%; Alternative Resources - 14.5%; Publicly Owned Entity - 17.1%; and End User - 15.92%). (See Vote 3 on Attachment 2).

Mr. Doot reported that NEPOOL would work with the ISO towards a joint filing, or if necessary or appropriate, separate filings that support the rights of affected participants whose data would be disclosed as a result of the Information Policy Changes.

OTHER BUSINESS

Mr. Doot reported that the next Committee meeting would be the December 7, 2012 Annual Meeting at the Colonnade Hotel in Boston. He reminded the Committee that the newest FERC Commissioner, the Honorable Tony Clark, would be in attendance and would offer remarks. He then reported that the process for identifying a Chairman for 2013 had been completed after the first round of confidential balloting, and Mr. Bowie had been re-~~elected~~selected to stand for a second term as Chairman.

There being no further business, the meeting adjourned at 11:40 a.m.

Respectfully submitted,

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David T. Doot, Secretary

**MEMBERS AND ALTERNATES PARTICIPATING IN
NOVEMBER 9 , 2012 SPECIAL PARTICIPANTS COMMITTEE MEETING**

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
511 Plaza LP	End User		Gus Fromuth	
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
Bangor Hydro-Electric Company	Transmission		Stacy Dimou	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing/Cross-Sound Cable (CSC)	Supplier		Jose Rotger	
Central Maine Power Company	Transmission		Sue Clary	
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Cianbro Companies	End User	Gus Fromuth		
Concord Municipal Light Plant	Publicly Owned		Gary Will	
Conn. Municipal Electric Energy Cooperative	Publicly Owned	Brian Forshaw		
Conservation Law Foundation	End User		N. Jonathan Peress	
Conservation Services Group	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Corinth Wood Pellets, LLC	End User	Gus Fromuth		
CP Energy Marketing (US) Inc. (Capital Power)	Supplier	Michelle Gardner		
DC Ebergy, LLC	Supplier	Bruce Bleiweis		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart		
Dragon Products Company	End User	Gus Fromuth		
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, Inc.	Generation		Ron Mackoviak	
EP Energy Massachusetts LLC	Generation	MQ Riding		
EquiPower Resources Management, LLC	Generation	Jim Ginnetti	William Fowler	
Exelon / Constellation	Supplier		William Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
First Wind Energy Marketing, Inc.	AR			Bob Stein
Food City, Inc.	End User	Gus Fromuth		
GenOn Energy Management, LLC	Generation	Philip Smith		
Granite Ridge/Merrill Lynch	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier		Robert Stein	
Hardwood Products Company	End User	Gus Fromuth	Jerry Tudan	William P. Short III
Harvard Dedicated Energy Limited	End User			Roger Borghesani
Hess Corporation	Supplier		Marji Philips	Nancy Chafetz
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Don Sipe		
IPR-GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Skiing	End User	Don Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	

MEMBERS AND ALTERNATES PARTICIPATING IN
NOVEMBER 9, 2012 SPECIAL PARTICIPANTS COMMITTEE MEETING

Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden's Inc.	End User	Gus Fromuth		
Massachusetts Attorney General's Office	End User		Fred Plett	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
MoArk, LLC	End User	Gus Fromuth		
Moose River Lumber Co., Inc.	End User	Gus Fromuth		
New England Building Materials, LLC.	End User	Gus Fromuth		
New England Power Company (NGRID)	Transmission	Timothy Brennan		
New Hampshire Office of Consumer Advocate	End User		Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Fernando DaSilva		
NU/NSTAR	Transmission		Calvin Bowie	
NRG Power Marketing, Inc.	Generation	Peter Fuller		
PalletOne of Maine	End User	Gus Fromuth		
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
Princeton Municipal Light Department	Publicly Owned		Gary Will	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
RJF – Morin Brick LLC	End User	Gus Fromuth		
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Rumford Paper Company	End User	Don Sipe		
St. Anselm College	End User	Gus Fromuth		
St. Joseph Health Services of Rhode Island	End User		Gus Fromuth	
Shipyard Brewing Co., LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Light Department	Publicly Owned		Brian Forshaw	
The Energy Consortium	End User	Roger Borghesani		
The Energy Council of Rhode Island	End User			Roger Borghesani
United Illuminating	Transmission		Alan Trotta	
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission	Francis 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		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital	End User		Gus Fromuth	
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
Z-TECH, LLC	End User		Gus Fromuth	

**ROLL CALL VOTES TAKEN AT
NOVEMBER 9, 2012 SPECIAL PARTICIPANTS COMMITTEE MEETING**

TOTAL

Participant Name	VOTE 1	VOTE 2	VOTE 3
GENERATION	17.10	12.83	0.00
TRANSMISSION	17.10	17.10	17.10
SUPPLIER	17.10	17.10	17.10
ALTERNATIVE RESOURCES	14.50	14.50	14.50
PUBLICLY OWNED ENTITY	17.10	17.10	17.10
END USER	15.20	17.10	15.92
% IN FAVOR	**98.10**	**95.73**	**81.72**

GENERATION SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
Dominion Energy Marketing, Inc.	F	F	A
Entergy Nuclear Power Marketing LLC	F	F	A
EP Energy Massachusetts, LLC	A	O	O
EquiPower Resources Management LLC	F	O	O
GenOn Energy Management, LLC	F	F	O
IPR-GDF SUEZ Energy Marketing NA	F	F	A
NextEra Energy Resources, LLC	F	F	A
NRG Power Marketing, LLC	F	F	O
IN FAVOR (F)	7	6	0
OPPOSED (O)	0	2	4
TOTAL VOTES	7	8	4
ABSTENTIONS (A)	1	0	4

TRANSMISSION SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
Bangor Hydro-Electric Company	F	F	F
Central Maine Power Company	F	F	F
NU / NSTAR	F	F	F
The United Illuminating Company	F	F	F
Vermont Electric Power Company	F	F	F
IN FAVOR (F)	5	5	5
OPPOSED (O)	0	0	0
TOTAL VOTES	5	5	5
ABSTENTIONS (A)	0	0	0

SUPPLIER SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
BP Energy Company	A	A	A
Brookfield Energy Marketing Inc. / CSC	F	F	A
Consolidated Edison Energy, Inc.	F	F	A
CP Energy Marketing (US) Inc.	F	F	A
DC Energy, LLC	A	A	A
Dynegy Marketing and Trade, LLC	F	A	A
Energy America, LLC	A	A	A
Exelon New England Holdings / Constellation	F	F	A
Granite Ridge/Merrill Lynch Commodities	F	A	A
H.Q. Energy Services (U.S.) Inc.	F	F	F
Hess Corporation	F	F	A
Integrys Energy Services, Inc.	A	A	A
LIPA	A	A	A
PSEG Energy Resources & Trade LLC	F	F	A
IN FAVOR (F)	9	7	1
OPPOSED (O)	0	0	0
TOTAL VOTES	9	7	1
ABSTENTIONS (A)	5	7	13

ALTERNATIVE RESOURCES SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
Renewable Generation Sub-Sector			
First Wind Energy Marketing	F	F	F
Distributed Generation Sub-Sector			
Conservation Services Group	F	F	F
Small DG Group Member	A	A	A
Load Response Sub-Sector			
EnerNOC, Inc.	F	F	A
Vermont Energy Investment Corp.	A	A	A
Small LR Group Member	A	A	F
IN FAVOR (F)	3	3	3
OPPOSED (O)	0	0	0
TOTAL VOTES	3	3	3
ABSTENTIONS (A)	3	3	3

**ROLL CALL VOTES TAKEN AT
NOVEMBER 9, 2012 SPECIAL PARTICIPANTS COMMITTEE MEETING**

PUBLICLY OWNED ENTITY SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
Ashburnham Municipal Light Plant	F	F	F
Boylston Municipal Light Department	F	F	F
Chicopee Municipal Lighting Plant	F	F	F
Conn. Municipal Electric Energy Coop.	F	F	F
Concord Municipal Light Plant	F	F	F
Groton Electric Light Department	F	F	F
Holden Municipal Light Department	F	F	F
Holyoke Gas & Electric Department	F	F	F
Hudson Light and Power Department	F	F	F
Hull Municipal Lighting Plant	F	F	F
Ipswich Municipal Light Department	F	F	F
Littleton (NH) Water & Light Dept.	A	A	F
Mansfield Municipal Electric Dept.	F	F	F
Marblehead Municipal Light Dept.	F	F	F
Mass. Municipal Wholesale Electric Co.	F	F	F
Middleborough Gas and Electric Dept.	F	F	F
Middleton Municipal Electric Dept.	F	F	F
Paxton Municipal Light Department	F	F	F
Peabody Municipal Light Plant	F	F	F
Princeton Municipal Light Department	F	F	F
Rowley Municipal Lighting Plant	F	F	F
Russell Municipal Light Department	F	F	F
Shrewsbury's Electric & Cable Ops	F	F	F
South Hadley Electric Light Dept.	F	F	F
Sterling Municipal Electric Light Dept.	F	F	F
Taunton Municipal Lighting Plant	F	F	F
Templeton Municipal Lighting Plant	F	F	F
Vermont Electric Cooperative	A	A	F
Vermont Public Power Supply Authority	F	F	F
Wakefield Municipal Gas & Light Dept.	F	F	F
West Boylston Municipal Lighting Plant	F	F	F
Westfield Gas & Electric Light Dept.	F	F	F
IN FAVOR (F)	30	30	32
OPPOSED (O)	0	0	0
TOTAL VOTES	30	30	32
ABSTENTIONS (A)	2	2	0

END USER SECTOR

Participant Name	VOTE 1	VOTE 2	VOTE 3
511 Plaza, LP	A	A	F
Associated Industries of Massachusetts	F	F	F
Cianbro Companies	A	A	F
Conservation Law Foundation	F	F	O
Corinth Wood Pellets, LLC	A	A	F
Dragon Products Company	A	A	F
Elektrisola, Inc.	A	A	F
Fairchild Semiconductor Corporation	A	A	F
Food City, Inc.	A	A	F
Hardwood Products Company	A	A	F
Harvard Dedicated Energy Limited	F	F	F
Industrial Energy Consumer Group	F	F	F
Maine Skiing, Inc.	F	F	F
Marden’s Inc.	A	A	F
Mass. Attorney General's Office	O	F	F
MoArk, LLC	A	A	F
Moose River Lumber Co., Inc.	A	A	F
New England Building Materials	A	A	F
NH Office of Consumer Advocate	A	A	A
PalletOne of Maine	A	A	F
RJF – Morin Brick LLC	A	A	F
Rumford Paper Company	F	F	F
St. Anselm College	A	A	F
St. Joseph Health Services of RI	A	A	F
Shipyard Brewing Co., LLC	A	A	F
The Energy Consortium	F	F	F
The Energy Council of Rhode Island	A	A	F
Union of Concerned Scientists	F	F	O
Westerly Hospital, The	A	A	F
Z-TECH, LLC	A	A	F
IN FAVOR (F)	8	9	27
OPPOSED (O)	1	0	2
TOTAL VOTES	9	9	29
ABSTENTIONS (A)	21	21	1

Document comparison by Workshare Compare on Wednesday, December 26, 2012 6:38:08 PM

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Description	#43023070v3<HARTFORD> - Preliminary NPC Mtg. Minutes 2012 Nov 9 (special meeting)
Document 2 ID	interwovenSite://HARTDMS/HARTFORD/43023070/4
Description	#43023070v4<HARTFORD> - Preliminary NPC Mtg. Minutes 2012 Nov 9 (special meeting) - post 12/18 comments
Rendering set	Opt5 - Dbl Underline, Strike, Moves

Legend:	
Insertion	
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Moved cell	
Split/Merged cell	
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Statistics:	
	Count
Insertions	34
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Moved from	2
Moved to	2
Style change	0
Format changed	0
Total changes	62

PRELIMINARY

The 2012 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, December 7, 2012 at The Colonnade Hotel, 120 Huntington Avenue, Boston, MA, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present, in particular welcoming FERC Commissioner Clark and State Regulators who joined the annual meeting.

APPROVAL OF MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the November 2, 2012 Participants Committee meeting that had been circulated in advance of the meeting, marked to show changes from the prior draft. Following motion duly made and seconded, those preliminary minutes, with an editorial change noted, were unanimously approved.

CONSENT AGENDA

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without comment or abstentions.

RESOLUTION OF APPRECIATION WILLIAM NUGENT

On behalf of the Committee, Mr. Bowie acknowledged Mr. William Nugent, Executive Director of NECPUC upon his retirement, and expressed appreciation for his contributions to the

Committee and to the region over the years. He presented Mr. Nugent with a small gift and a framed resolution that read as follows:

> ***WHEREAS,*** *Mr. William Nugent has been a valued participant in the New England stakeholder process for many years, most recently as the Executive Director of the New England Conference of Public Utilities Commissioners (NECPUC) and previously as the Chairman of the Maine Public Utilities Commission and President of the National Association of Regulatory Commissioners; and*
>
> ***WHEREAS****, Bill has tirelessly ensured that he is aware of and current on NEPOOL matters and has provided invaluable communication of those efforts to NECPUC members; and*
>
> ***WHEREAS****, Bill has been instrumental in improving and maintaining good relations among NEPOOL and NECPUC members; and*
>
> ***WHEREAS****, Bill has earned great admiration and respect for his role in the evolution of New England's electric industry; and*
>
> ***WHEREAS****, having made enduing and valuable contributions to our region and our industry for many years, Bill has announced his intention to retire at the end of this year,*
>
> ***NOW, THEREFORE****, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its gratitude for the opportunity to work with Bill during his many years of collegial collaboration with NEPOOL and wishes him many years of good health, fortune and happiness.*
>
> *Signed and presented by the NEPOOL Participants Committee Officers on behalf of the NEPOOL Participants this 7th day of December, 2012, in Boston, Massachusetts.*

Mr. Nugent expressed appreciation to the Committee, to the colleagues he had worked with for over 22 years in regulation in New England, and for all the friendships he had forged along the way. He stated that the Participants Committee, as were all of the region's stakeholder meetings, was marked by a wonderful process of openness and exchange of ideas, with everyone contending for their own interests, but out of which came a stronger system that more purposefully served the people and the economy of the region. He explained his comfort with the timing of his retirement given that the states' participation in the NEPOOL process had never been stronger, supported and strengthened as it was by the formation and engagement of NESCOE in the process.

COMMENTS OF FERC COMMISSIONER TONY CLARK

Mr. Doot welcomed and introduced the Honorable Tony Clark, newest Commissioner of the FERC. Commissioner Clark began by noting that Mr. Nugent was the President of ~~NARUC~~the National Association of Regulatory Utility Commissioners (NARUC) when he first joined NARUC in 2001, and he added his thanks to Mr. Nugent for his many years of dedicated service to the energy industry. Commissioner Clark shared his view that recent complaints heard concerning a "lack of a national energy policy" were indicative of viewpoints of those who felt political leaders favored a particular technology over one that they prefer be favored. Commissioner Clark suggested that there was a *de facto* national energy policy, which was one in which the nation chooses the cheapest form of energy at the time. He agreed with Commissioner Cheryl LaFleur's summary that "in the energy industry, we tend to be serial monogamists", layering on some form of subsidy, whether direct or indirect, tax/or RPS-driven. He noted that, over the past several years, there had been substantial investment in various energy sectors. He said the nation had, for the first time in at least 40 years, an opportunity to choose to be energy secure, thanks to the shale gas and shale oil revolution.

Addressing his regulatory philosophy and goals as a FERC Commissioner, he explained his opposition to the making of uneconomic choices to advantage one particular source of energy over another, even where both may meet all applicable environmental and reliability standards. He indicated his goal as a Commissioner was to help create a regulatory climate that would encourage capital investment and would not be not overly prescriptive or heavy-handed in determining specific outcomes. He outlined ~~the following~~ the following ways in which he believed the FERC could achieve that objective:

1. Encouragement through appropriate economic signals (avoiding political ones).
2. Reasoned decision-making on a record and promotion of due process.
3. Promotion of certainty and avoidance of surprises to the greatest degree possible.
4. Timely decision-making and moving on.

Commissioner Clark then reviewed matters of particular FERC focus, including:

- Gas-Electric interdependency issues. He explained that the degree of risk to a system from these issues depended on the number of affirmative answers to the following questions:
  - Are you a gas dependent region?
  - Are you a cold weather area with seasonal fluctuations?
  - Are you a restructured retail market region?
  - Are you in a constrained pipeline region?

  He noted that New England, unlike other regions of the country, answers yes to all these questions.
- Market policing activities. He referenced recently-issued FERC enforcement orders.
- Transmission incentive policies. He referred to the recent FERC order describing evolution of these policies.
- Capacity markets and constructs. He explained that time was an issue for all the restructured markets.

Following a general reminder concerning the prohibition against *ex parte* communications with the Commissioner, members then asked questions of Commissioner Clark, including questions addressing the FERC's focus on market uncertainty and challenges to market liquidity presented by heightened enforcement activities, as well as responses to the Dodd-Frank legislation. Addressing FERC's enforcement activity, Commissioner Clark explained that FERC's enforcement activity had arisen mainly from the powers granted it in the Energy Policy Act of 2005, particularly with respect to anti-market manipulation. Although FERC's experience with anti-market manipulation enforcement authority was relatively new, the general area of law ~~is~~was not novel, based as it was on decades-old ~~SEC~~ rules of the U.S. Securities and Exchange Commission (SEC). He stated that the ~~Commission~~FERC's threshold to establish intent to defraud and intent to manipulate markets was very high, and was informed by years of experience under securities laws. He noted that a market participant could not use its position to make uneconomic trades and take uneconomic positions to order to influence outcomes in other markets. He acknowledged that the timing of some recent enforcement actions was a function of the establishment of that capability within the FERC, and was certain legal challenges would almost certainly follow, but indicated that FERC enforcement would be active in the anti-market manipulation area.

In response to a member's question, Commissioner Clark indicated that the notion of subsidies for particular energy resource types often, but not always, lurked in the decision-making background. He identified challenges associated with policy and judgment calls in restructured markets where free market and fully regulated principles ~~are~~were muddled together. He indicated regulators, including the FERC Commissioners, would be called on to make course corrections, but should take care to not surprise stakeholders and the industry as they make them.

Commissioner Clark encourage those interested, whenever not otherwise legally prohibited from doing so, to meet with him and his staff. He explained why he viewed such interaction as helpful, even essential, to his job as a Commissioner. He indicated his plan to visit New England as often as practicable, and invited those able to come to Washington and meet with him.

On behalf of NEPOOL, Mr. Bowie expressed appreciation to Commissioner Clark and the other FERC representatives for their attendance and participation in the Participants Committee ~~A~~annual ~~M~~meeting.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings which had occurred since the last Participants Committee meeting and which had been circulated in advance of the meeting. He expressed appreciation to everyone for the hard work and engagement on the issues outlined in the ISO's Strategic Planning Initiatives. He predicted that the region would be even busier in 2013 as it moved from discussion at a conceptual-level on issue definition to a more action-oriented framework, including work to support filings with the FERC on each of the issues described.

He highlighted that, as the ISO did at the beginning of each calendar year, the ISO would be meeting with the NEPOOL Officers, NECPUC and NESCOE to discuss the ISO's 2013 Work Plan. That meeting was scheduled for January 3, 2013. A report and follow-up discussion would then be scheduled for the January 4 Participants Committee meeting, with supporting materials to be circulated to the Officers and the Committee in advance of those meetings.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada reviewed highlights from the December COO report, which was circulated in advance of the meeting and posted on the ISO website. Focusing specifically on report highlights, he indicated that in November: (i) natural gas prices were almost 80% higher and oil prices were 3.7% lower than October 2012 average values; (ii) Real-Time Hub LMPs were up over 55% from October 2012 averages; (iii) Net Commitment Period Compensation

(NCPC), totaling $15 million and representing 2.8% of the Energy Market value, was $4.4 million higher than October 2012 NCPC; (iv) first contingency payments, totaling $10.5 million, were $4.4 million higher than October's first contingency payments, with nearly half experienced during the first few days of the month during Hurricane Sandy and after due to the loss of a large generation resource, and the remainder largely due to minimum flow requirements triggered by ~~an~~ a Maine Power Reliability Program (MPRP) project-related line outage (also expected to occur during a few days in December); (v) second contingency payments totaled $1.8 million, which was up $1 million from the October total, ~~which were~~and due primarily to unplanned outages in NEMA and planned unit outages in Maine; (vi) voltage support payments totaled $2.6 million (almost all of which was in Western Massachusetts); and (vii) distribution payments totaled $1 million. He reported that, based on a 50/50 load forecast, the lowest Winter Operable Capacity Margin was projected for the week beginning December 1, 2012. He noted that outages of certain non-gas fired generation had been rescheduled to shoulder months from the winter months to reduce peak load exposure and expressed his appreciation to those resources for their willingness to reschedule those outages.

Dr. Chadalavada reviewed a slide illustrating the very high volatility of Real-Time LMPs during November. He noted there were eight to nine days with substantial spikes during the morning or evening peaks, almost all attributable to Thirty-Minute Operating Reserve (TMOR) and Ten-Minute Spinning Reserve (TMSR) constraints, further intensified by higher than forecasted load and unplanned forced outages during the morning and afternoon peaks. He referenced a second slide showing the trend in higher fuel prices, particularly natural gas prices. In response to questions, Dr. Chadalavada indicated that the ISO was guardedly optimistic that there would be sufficient fuel inventory to get through a winter cold snap, but stated that ISO operations would continue to closely monitor ~~those~~fuel inventory levels, in collaboration with asset owners, and the ability to restore inventory levels to assure system reliability would not be compromised. Finally, he pointed out a new slide, included at members' requests, that listed Minimum Generation Emergency warnings and declarations for the month.

Turning to the 2012/2013 Winter Supplemental Commitment, and in follow-up to questions raised in November regarding the impact of varying levels of increased supplemental commitment on LMPs, Dr. Chadalavada directed the Committee to and reviewed a new slide reflecting an analysis of the impact on both NCPC and LMPs of increased supplemental commitment during the 2012/2013 Winter.

In response to questions, Dr. Chadalavada provided additional explanation concerning the underlying system characteristics resulting in the November price spikes. He indicated that price formation, would be a focus in 2013 and further discussed at the January meeting. He provided additional information concerning potential impacts of Hurricane Sandy-related damage to generation resources, in the aggregate roughly 1,200 MW, on winter operations. He indicated that the ISO was particularly concerned about the possibility of a protracted or multiple cold snap(s), conditions which had not been experienced by the region for at least five years. Should a cold weather event be forecast, he expected the ISO would be conservative with respect to Supplemental Commitment. He reviewed the concerns and actions the ISO would have or take in response to the increased risk that such a cold weather event early in the winter period might impose.

QUARTERLY MARKETS REPORT

Mr. David LaPlante, ISO Vice President of Market Monitoring (IMM), referred the Committee to the presentation of the Third Quarter Quarterly Markets Report circulated with the meeting materials in advance of the meeting. He reported that the energy market was generally unconcentrated and structurally competitive, with price outcomes that, by and large, reflected supplier short-run marginal costs, consistent with those expected of a competitive market. He noted that the Real-Time price remained a couple of dollars higher than the Day-Ahead price, on average, and as a result, not much increase in load clearing in the Day-Ahead Market. He noted that gas prices were ~~a lot~~much lower in the third quarter of 2012 than they were during the third quarter of 2011, though gas prices had risen noticeably during the first month of the fourth quarter.

Focusing on a chart that illustrated a significant decrease~~d~~ in the number of virtual transactions since 2009, Mr. LaPlante attributed the drop to the change in allocation of uplift charges (from second contingency and local to first contingency and system wide) and suggested that the allocation to virtual transactions had contributed to lower levels of load clearing Day-Ahead. He reiterated prior statements regarding the importance of changing that uplift allocation so that virtuals could more easily participate profitably in the market and thereby encourage more load to clear, and generation to be committed, Day-Ahead.

In response to members' questions, Mr. LaPlante acknowledged that the underlying economics of lower overall energy prices also impacted virtuals, reducing the headroom for profits, and further exacerbating the cost allocation impact. ~~The~~A member noted that the additional cost of increased financial assurance requirements since 2009 may have also been a factor. Mr. LaPlante indicated that the amount of load bid Day-Ahead had remained relatively constant (between 91% and 95% of Real-Time load) over the past couple of years, which was a bit surprising given the price premium experienced in the Real-Time Energy Market.

Mr. van Welie added that the lower Day-Ahead load presented operational challenges, forcing the ISO to address energy requirements in the Reserve Adequacy Assessment (with associated increases in uplift), in addition to the contingency issues that could arise. He suggested that addressing Real-Time price formation issues referred to earlier in the meeting would change the Day-Ahead Market bidding incentives for load and improve operational and economic performance. A member encouraged the ISO to evaluate the load volumes scheduled during periods of price volatility.

Related to price formation, Mr. LaPlante referred to a memo circulated to generators in early November that outlined how the IMM would view and mitigate re-offers. Because of the difficulty of obtaining gas in the intra-day markets, the IMM had encouraged those resources re-offering their resources to do so at prices that ~~will~~would enable them to acquire gas and be available, and for dual-fuel resources to go to oil if they ~~are~~were at risk of not procuring gas intra-day. He reported that, since early November, the IMM was no longer using the Day-Ahead gas index price to evaluate re-offers, since that index price was too low to reflect intra-day prices, and would, if used, understate the cost of operating the system reliability and could potentially put generators at risk of being required to provide energy at a loss. Based on experience to date, Mr. LaPlante believed the change to have worked reasonably well, helping to improve price formation and better price reliability risk. He hoped that, with additional implementation refinements underway, the change would improve the reliable operation of the system. Members with dual-fuel resources expressed their appreciation for the IMM's efforts.

On a final note, Mr. LaPlante referred to a proposed new format for the Quarterly Markets Report that had been described in additional materials circulated in advance of the meeting. He explained that, like the current report, the new format would contain information on market outcomes, system conditions and market competitiveness, but would place more emphasis on IMM explanations for why certain market outcomes or system conditions occurred during the relevant period. Mr. LaPlante stated that the goal of the new format was to provide stakeholders with useful insights into the IMM's on-going market surveillance and analysis. He reported that he would review the format with NECPUC during the IMM's monthly call with NECPUC the following week and would be pleased to receive any Participant input or suggestions on the new format through the end of the month. He indicated plans to begin using the new format with the Quarterly Markets Report for the first quarter of 2013.

2012 NEPOOL ANNUAL REPORT

Mr. Doot referred the Committee to the 2012 NEPOOL Annual Report, which was circulated in printed form at the meeting. He encouraged Committee members to review the report and to provide feedback as to format and/or content, noting that the annual report was adjusted each year based on feedback from the Committee and regulators. He expressed his gratitude to the Day Pitney team led by Mr. Harold Blinderman and Cindy Jacobs that had assembled the ~~a~~Annual ~~r~~Report.

Mr. Doot highlighted the theme for the 2012 Annual Report which, as outlined in Mr. Bowie's message, was NEPOOL "Bridging Today's Challenges", with NEPOOL as the keystone to the well-traveled stakeholder bridge from diversity of interests on one side, to consensus and agreement, on the other side. He particularly commended the NEPOOL Officers for all their hard work during 2012 on behalf of the Committee and the Participants.

He highlighted key issues of focus for the Pool in 2012 addressed in the report, including Order 1000 compliance, FCM design, and gas-electric coordination. He noted the number of Principal Committee meetings and legal proceedings monitored by the Participants Committee during 2012, which underscored the intense level of stakeholder activity. He indicated that the NEPOOL ~~o~~Officers and Counsel welcomed feedback on how they might be more effective and efficient with the members' time and support and encourage more informed and fully prepared engagement in the NEPOOL stakeholder process.

ELECTION OF 2013 PARTICIPANTS COMMITTEE OFFICERS

Mr. Bowie referred the Committee to the resolution circulated in advance of the meeting to re-elect the 2012 Participants Committee Officers for 2013. Mr. Doot noted that, as announced at the November 9 special meeting, Mr. Bowie had been selected during the first round of secret balloting as candidate for Chair for a second term.

Following motion duly made, and seconded, the Committee considered and unanimously approved the following motion:

> 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 2013 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Calvin A. Bowie
Vice-Chair	Brian E. Forshaw
Vice-Chair	August G. "Gus" Fromuth
Vice-Chair	Peter D. Fuller
Vice-Chair	Joel S. Gordon
Vice-Chair	Doug Hurley
Secretary	David T. Doot
Assistant Secretary	Paul N. Belval

APPROVAL OF 2013 ESTIMATED NEPOOL BUDGET

Mr. Joel Gordon, Budget & Finance Subcommittee (Subcommittee) Chairman, then referred to and reviewed the materials that were circulated in advance of the meeting regarding the 2013 NEPOOL budget (2013 Budget), which represented less than a 3% increase from the 2012 budget (a copy of the 2013 Budget as presented is included as Attachment 2 to these minutes). Mr. Gordon reported that the Subcommittee recommended the adoption of the 2013 Budget at its November 19, 2012 meeting. In response to questions and comments received in connection with the 2013 Budget review, Mr. Gordon noted plans for the Subcommittee to specifically monitor throughout 2013 progress on certain budget line items, including those for meeting expenses and Pool Counsel. He urged all members to participate in the Subcommittee or simply to provide feedback to the Subcommittee on areas of concern and/or satisfaction with respect to the services NEPOOL is providing to its membership.

The following motion was then duly made, seconded, and, without further discussion, unanimously approved:

> RESOLVED, that the Participants Committee adopts the estimated budget for Participant Expenses for 2013 as presented at this meeting.

OATT ATTACHMENT K SECTION 4.1(C)(IV) COMPLIANCE AMENDMENT

Following the exit from the meeting by Commissioner Clark and FERC staff, Mr. Donald Gates, Transmission Committee Chair, referred the Committee to the materials circulated in advance of the meeting regarding a revision to Section 4.1(c)(iv) of Attachment K to Section II of the ISO Tariff (the OATT) to be made in response to an October 26, 2012 FERC order in Docket No. ER12-1914. He explained that the FERC order required one specific change to the language of Attachment K that addressed the timing of when the ISO must present information about de-list bids and Non-Price Retirement Requests that it rejects for reliability reasons. He reported that the Reliability Committee had recommended Participants Committee support for the change at a special November 16, 2012 meeting, with only CLF opposing that recommendation. The matter had been placed on the agenda for discussion at the request of CLF.

Mr. Doot explained that following that Transmission Committee vote, the ISO had submitted, on November 26, 2012, a compliance filing in accordance with the timeframe directed in the October 26 order. Accordingly, any discussion at the meeting would be reflected in any comments submitted by NEPOOL in response to the compliance filing.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the recommendation of the Transmission Committee to revise Attachment K of Section II of the ISO Tariff, as reflected in the materials distributed to the Participants Committee for its December 7, 2012 meeting.

Addressing CLF's concerns with the proposed changes, the CLF representative argued that the proposed changes fell short of addressing the central concern embodied in FERC's orders – namely, that Attachment K make clear exactly when critical market information will be made available to Market Participants. He suggested that the proposed revisions would constrain the departure of uneconomic units from the market, and thereby adversely affect how companies would deploy capital to add new resources to the New England Market. He emphasized that it was critically important that the ISO, both through words and actions, send appropriate signals to the market that market-based solutions could meet reliability challenges, and avoid actions that might dilute or undermine those signals. To that end, he exhorted the ISO during 2013 to advance Market Resource Alternatives, and in words and actions express confidence in market-based solutions.

Without further discussion, the motion was then voted and approved, with an opposition by CLF and abstentions by each of the Large Market Participant End Users, Harvard, IECG, NH OCA, CT OCC, MOPA, PowerOptions, TEC-RI, UCS, and the AR Sector Renewable Generation Small Group Member.

ADDITIONAL CONDITIONS TO MEMBERSHIP OF NEGAWATT BUSINESS SOLUTIONS

On behalf of the Membership Subcommittee, Mr. Patrick Gerity referred the Committee to materials that had been circulated in advance of the meeting pertaining to the membership application of Negawatt Business Solutions (Negawatt). He summarized those materials, explaining that Committee action was required because the delegation of authority to the Membership Subcommittee was not sufficient for the Subcommittee to take final action on Negawatt's application under the circumstances. He identified ISO's concerns with the participation by Negawatt in the New England Markets arising from the ISO's review of information provided by Negawatt in compliance with the Financial Assurance Policy's Minimum Eligibility Requirements. In particular, he reported that the ISO was uneasy with a significant contingent liability outstanding against a principal of Negawatt, as well as prior history of poor compliance with the Financial Assurance Policy by Related Persons of Negawatt.

To mitigate those concerns, the ISO proposed, and the Membership Subcommittee recommended for approval and support, three additional conditions to the acceptance of Negawatt into the Pool and the New England Markets (the Conditions), in addition to the Standard Conditions and Waivers applicable to all new NEPOOL members. Mr. Gerity reviewed with and explained the Conditions to the Committee. He reported that, with the Conditions, the Subcommittee recommended Participants Committee approval of Negawatt's membership in the Pool and support for the imposition of the Conditions as prerequisites to Negawatt's participation in the New England Markets.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports and approves the participation of Negawatt Business Solutions (Negawatt) in the New England Markets, subject to the following conditions: (1) that NEPOOL Counsel and the ISO find the application by Negawatt complete; (2) that Negawatt sign and return the Standard Membership Conditions, Waivers and Reminders letter; and (3) that Negawatt execute a document setting forth the following additional conditions and understandings:
>
> - Until the day that is the first day of the first calendar month following a final and unappealable resolution of the civil litigation against Negawatt's Principal Gary D. Mole that is in his favor:
>
>   (1) Negawatt will provide a supplemental Letter of Credit (separate from and in addition to the applicable financial assurance required under the FAP) in an amount satisfactory to NEPOOL's Independent Financial Advisor and the ISO's Chief Financial Officer. Such amount will be based on the additional financial assurance table contained in Section II.A.4(c) of the FAP;

(2) Negawatt will forego holding any long-term Financial Transmission Rights ("FTRs") or participating in any auction for annual or long-term FTRs; and

- For a period of one year from the date of the effectiveness of its NEPOOL membership:

(3) Negawatt will have an ongoing obligation to (i) timely meet all payment deadlines set forth in the Billing Policy, and (ii) timely provide such additional financial assurance as may be required pursuant to the Financial Assurance Policy. In the event that a late payment, Payment Default, Credit Test default, or other Financial Assurance Default is not timely cured and results in suspension, the ISO and NEPOOL shall have the right to terminate Negawatt's participation in the New England Markets and Negawatt's NEPOOL membership.

Mr. Adam Gusman, Negawatt Assistant General Counsel, stated that Negawatt did not object to the Conditions. He further indicated that Negawatt's Related Person, Glacial Energy of New England Inc. (Glacial), had not had any defaults since its capital structure was revised the prior December, and expected that trend to continue. In response to questions, he confirmed that Glacial was a Massachusetts-licensed retail electricity supplier, but that Negawatt, as a demand response service provider, did not expect to be required to be licensed in Massachusetts, though he indicated Negawatt would pursue all applicable registration and license requirements.

In response to questions, Mr. Marc Montalvo explained the reasoning underlying the Conditions' limitation on annual but not monthly participation in the Financial Transmission Rights (FTR) Market, explaining the difficulty in managing the financial risk of a default with respect to long-term FTR obligations that was not otherwise present for monthly FTR positions. He also explained the various considerations that contributed to the ISO's assessment, both with respect to Negawatt specifically, and Market Participants and applicants more generally.

Following further discussion, the Conditions were then voted and unanimously approved, with abstentions noted by NU, UI, and VELCO.

EASTERN INTERCONNECTION PLANNING COLLABERATIVE (EIPC) PROCESS REPORT

Mr. Doot referred the Committee to the materials regarding EIPC circulated in advance of the meeting. Mr. Doot encouraged members with questions or concerns to contact Mr. Runge.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report that had been circulated in advance of the meeting. He highlighted two proceedings where developments suggested resolution was near. First, in the FCA7 Qualification Informational Filing, the ISO had indicated the day before that, based on new facts presented and for reasons it explained, it did not oppose the waivers requested by Footprint, Brookfield or HQ US, and should the FERC be willing to grant the waivers requested, the ISO was satisfied that the resources could be qualified from a reliability standpoint. Turning to the Vermont Yankee (VY) Dynamic De-List Bid contested in the FCA5 results proceeding, Mr. Doot indicated that, in light of the ISO's acceptance of the VY Dynamic De-List Bid, the Settling Parties had agreed to, and would soon, request the dismissal of the proposed Settlement Agreement then pending, but contested by the Participants Committee. With respect to remaining proceedings, he noted that there continued to be a high level of activity and encouraged members with questions on the content of the report, or suggestions with respect to its format or level of detail, to contact either Mr. Gerity or him.

In response to a member's question concerning NEPOOL's response to the December 3, 2012 filing of FCA8 FCM revisions that was due on December 24th, Mr. Doot indicated that

NEPOOL planned to provide the FERC with a full report on what transpired during the Participants Processes, including identifying amendments that were supported as part of those processes. He encouraged any members with suggestions, comments or concerns to provide them to their Sector Officers.

COMMITTEE REPORTS

Mr. Doot noted the memo circulated in advance of the meeting from Mr. Fernando DaSilva, Chairman of the NEPOOL Audit Management Subcommittee (NAMS), concerning the ISO's Service Organization Controls Report 1 (SOC-1) (formerly known as the SAS70 audit report) issued by KPMG for the October 2011 to September 2012 period. He encouraged anyone with questions or concerns on what otherwise appeared to be a "clean bill of health" to contact Mr. DaSilva so that a determination could be made whether to hold a NAMS meeting in follow-up to the SOC-1 report.

Mr. Doot also indicated that, in response to members' feedback, another special, joint meeting of the Markets and Reliability Committees would be held in January to further discuss FCM Performance Incentives. Those interested were requested to get any questions or other comments to the ISO in writing so that the meeting could be efficiently and effectively organized.

OTHER BUSINESS

Mr. Doot circulated the calendar for the remainder of December 2012 and January 2013. He highlighted that the Gas-Electric Focus Group was next scheduled to convene on December 19 at the DoubleTree Hotel in Westborough, MA. He noted that the Participants Committee

January 2013 meeting was also scheduled to be held at the Westborough DoubleTree Hotel, on January 4, and the February meeting would be at the Sheraton Framingham Hotel & Conference Center on February 1, 2013. Recalling the discussion concerning Participant Expenses earlier in the meeting and the desire to keep meeting expenses down, Mr. Doot noted his expectation that a number of Participants Committee meetings in 2013 would be held outside of Boston, and encouraged members to pay added attention to the venues identified in upcoming meeting notices.

Following expression of well wishes to members for safe and happy Holidays, the meeting adjourned at 12:30 p.m., after which there was a New Member Orientation.

Respectfully submitted,

____

David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 7, 2012 ANNUAL PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
511 Plaza LP	End User	William P. Short III		
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
Bangor Hydro-Electric Company	Transmission	Jeff Jones	Stacy Dimou	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing Inc. / CSC	Supplier	Nicolas Bosse (tel)	Jose Rotger	
Calpine Energy Services, LP	Supplier	John Flumerfelt		
Central Maine Power Company	Transmission		Sue Clary (tel)	
Cianbro Companies	End User			William P. Short III
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Comverg, Inc.	AR	John Driscoll		
Concord Municipal Light Plant	Publicly Owned		Gary Will	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User			Joe Rosenthal
Conservation Law Foundation (CLF)	End User		Naim Jonathan Peress	
Conservation Services Group (CSG)	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Corinth Wood Pellets LLC	End User			William P. Short III
CP Energy Marketing (US) Inc. (Capital Power)	Supplier	Michelle Gardner (tel)		
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart (tel)		
Dragon Products Company LLC	End User			William P. Short III
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User			William P. Short III
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, Inc.	Generation		Ron Mackowiak	
EP Energy Massachusetts, LLC	Generation	M.Q. Riding		
EquiPower Resources Management, LLC	Generation	Jim Ginnetti	William Fowler	
Exelon New England Holdings / Constellation	Supplier	Steve Kirk	William Fowler	
Fairchild Semiconductor Corporation	End User			William P. Short III
First Wind Energy Marketing, Inc.	AR			Francis Pullaro; Robert Stein
Food City, Inc.	End User			William P. Short III
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
GenOn Energy Management, LLC	Generation	Philip Smith		
Granite Ridge/Merrill Lynch	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier		Robert Stein	
Hardwood Products Company	End User			William P. Short III
Harvard Dedicated Energy Limited	End User	Mary Smith		Roger Borghesani
Hess Corporation	Supplier		Marji Phillips	Nancy Chafetz
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald Sipe (tel)		

**MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 7, 2012 ANNUAL PARTICIPANTS COMMITTEE MEETING**

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
IPR-GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Kimberly-Clark Corporation	Supplier			Vicki Karandrikas (tel)
Linde Energy Services	Supplier			Vicki Karandrikas (tel)
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Public Advocate Office (ME OPA)	End User	Agnes Gormley		
Maine Skiing, Inc.	End User	Donald Sipe (tel)		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden’s Inc.	End User			William P. Short III
Mass. Attorney General's Office	End User	Fred Plett		Jesse Reyes
Mass. Municipal Wholesale Electric Co. (MMWEC)	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
Millennium Power Partners	Generation		Ken Dell Orto	
MoArk, Inc.	End User			William P. Short III
New England Building Materials	End User			William P. Short III
New England Power Company (National Grid)	Transmission	Timothy Brennan		
New Hamp. Office of Consumer Advocate (NH OCA)	End User	Paul Peterson	Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Fernandno DaSilva		
NU / NSTAR	Transmission	James Daly	Calvin Bowie	Bob Clarke; Joe Staszowski (tel)
NRG Power Marketing, Inc.	Generation	Peter Fuller		
PalletOne of Maine	End User			William P. Short III
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cindy Arcate		Paul Person; Sarah Jackson
PPL EnergyPlus (PPL)	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Vicki Karandrikas (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member - LR Sub-Sector	AR	Brad Swalwell (tel)		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
RJF-Morin Brick LLC	End User			William P. Short III
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Rumford Paper Company	End User	Donald Sipe (tel)		
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User			William P. Short III
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
St. Anselm College	End User			William P. Short III
St. Joseph Health Services of Rhode Island	End User			William P. Short III
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Light Department	Publicly Owned		Brian Forshaw	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	

**MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 7, 2012 ANNUAL PARTICIPANTS COMMITTEE MEETING**

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
The Energy Council of Rhode Island	End User			Roger Borghesani
TransCanada Power Marketing Ltd.	Generation		Mike Hachey	
Union of Concerned Scientists (UCS)	End User	Paul Peterson		
United Illuminating Company, The (UI)	Transmission		Alan Trotta	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori	Bill Ryan (tel)	Mark Sciarrotta
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett (tel)		
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital	End User			William P. Short III
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
ZTECH, LLC	End User			William P. Short III

ATTACHMENT 2

ESTIMATED 2013 NEPOOL BUDGET COMPARED TO
2012 NEPOOL BUDGET AND 2012 PROJECTED ACTUAL EXPENSES

Line Items	2013 Proposed Budget	2012 Approved Budget	2012 Current Forecast
NEPOOL Counsel Fees (1)	$3,600,000	$3,600,000	$3,600,000
NEPOOL Counsel Disbursements (1)	$ 55,000	$ 55,000	$ 55,000
Independent Financial Advisor Fees and Disbursements (2)	$ 60,000	$ 75,000	$ 60,000
Committee Meeting Expenses (4)	$ 650,000	$ 460,000	$ 800,000
Review Board Compensation (5)	$ 112,000	$ 112,000	$ 112,000
Review Board Administrative and Support Expense	$ 30,000	$ 30,000	$ 25,000
CFTC Counsel (6)	$ 10,000	$ 25,000	$ 25,000
Generation Information System (3)	$1,065,000	$1,065,000	$1,065,000
Credit Insurance Premium (3)	$ 425,000	$ 425,000	$ 425,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (7)	$ -	$ -	$ -
SUBTOTAL EXPENSES	$6,007,000	$5,847,000	$6,167,000
Revenue			
NEPOOL Membership Fees (3) (8)	($1,750,000)	($1,900,000)	($1,770,000)
Generation Information System (3) (9)	($1,065,000)	($1,065,000)	($1,065,000)
Credit Insurance Premium (3) (10)	($ 425,000)	($ 425,000)	($ 425,000)
TOTAL REVENUE	($3,240,000)	($3,390,000)	($3,260,000)
TOTAL NEPOOL EXPENSES	**$2,767,000**	**$2,457,000**	**$2,907,000**

ATTACHMENT 2

Notes

(1) 2013 NEPOOL Counsel fees and disbursements are estimated to remain consistent with 2012 budgeted levels. Fees of NEPOOL's CFTC counsel associated with the ongoing efforts of the Dodd Frank Working Group are accounted for separately in this estimated budget.

(2) 2013 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2013 proposed estimate provided by ISO New England Inc. (ISO).

(4) Committee meeting expenses were above the budgeted amount in 2012 due primarily to expenses associated with 12 FCM Working Group meeting and increased costs associated with the summer meetings.

(5) 2013 proposed estimate assumes: (i) no change to current Review Board arrangements; (ii) three or fewer appeals in 2013; and (iii) no change in the annual retainer paid to each of the three members of the Review Board, which is $36,000, with an additional $4,000 paid to the Board's Chairman.

(6) The NEPOOL officers approved a $25,000 budget for 2012 to retain separate counsel associated with the ISO's requests for exemptions from CFTC regulation under the Dodd Frank Act. The estimated budget for 2013 is for additional work associated with the final exemption that is expected to be issued in 2013 and with comments on the ISO's requested supplemental exemption related to bilateral transactions.

(7) At its June 4, 2010 meeting, the Participants Committee approved a total expenditure of $80,000 for the NAMS Consultant. The $80,000 approved expenditure was spread across 2010 and 2011 ($42,000 budgeted in 2011). To date, $53,300 has been spent in 2010 and 2011. The remaining $26,700 was not budgeted to be spent in 2012. Per the materials distributed to the Participants Committee for its September 9, 2011 meeting by the NAMS Chair, that amount is to be set aside in the event that the NAMS Chair, in coordination with NAMS members, determines that the involvement of the NAMS Consultant is needed prior to the next scheduled NEPOOL Operations Audit.

(8) The 2012 forecast for NEPOOL membership fees is based on 295 members at $5,000 each, 2 members at $1,500 each, 4 members at $1,250 each, 23 members at $1,000 each, 24 members at $500 each, and $119,000 in additional fees for 28 Large End Users. The 2013 proposed estimate is based on the 2012 actual receipts through September 2012, plus a forecast (a) for new members of 10 members at $5,000 each, 2 members at $1,000 each, 3 members at $500 each, and (b) for terminated members of 20 at $5,000 each, 2 at $1,250 each, 2 at $1,000 and 9 at $500 each.

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

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

CONSENT AGENDA

From the notice of actions of the ***Markets Committee***[1] meeting dated December 13, 2012 which has been previously circulated:

1. **Compliance Changes to Manuals M-11, M-28 and M-35 (FA and Regulation IBTs)**

   Support revisions to ISO New England Manuals M-11 M-28 and M-35 to implement the elimination of Internal Bilateral Transactions for the Regulation Market, as recommended by the Markets Committee at its December 11-12, 2012 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.

2. **Revisions to MR 1, MR 1 App. F and Tariff (Definitions) (PRD Full Integration Updates)**

   Support revisions to Market Rule 1, Appendix E to Market Rule 1 and Section I.2.2 of the Tariff to implement the Price-Responsive Demand Full Integration Updates, as recommended by the Markets Committee at its December 11-12, 2011 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved with 7 oppositions (Generation (1); Supplier (1); AR (2); and End User (3)).

From the notice of actions of the ***Reliability Committee***[2] meeting dated December 18, 2012 which has been previously circulated:

3. **Revisions to OP6 (System Restoration and Attachments)**

   Support revisions to ISO Operating Procedure (OP) No. 6 (System Restoration) to implement retirement of all Appendices (A-G) as they become part of new MLCC 18 (System Restoration and Attachments), as recommended by the Reliability Committee at its December 18, 2012 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved, with the Publicly Owned Entity Sector all opposed.

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[1] Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/actions/index.html

[2] Reliability Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/actions/index.html

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Harold M. Blinderman and Sebastian M. Lombardi, NEPOOL Counsel

DATE: December 26, 2012

RE: Tariff Revisions to the Day-Ahead Energy Market and Reserve Adequacy Assessment Timelines

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At its January 4, 2013 meeting, the Participants Committee will be asked to consider supporting revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Section I.2.2 (Definitions), and the deletion of Appendix H to Market Rule 1, to implement a shift in the Day-Ahead Energy Market ("DAM") and Reserve Adequacy Assessment ("RAA") timelines. This memorandum summarizes information pertaining to that consideration and includes a form of resolution.

By way of brief background, the ISO has proposed to modify the DAM and RAA schedules so that both activities are completed ahead of the Day-Ahead gas nomination cycle deadlines. Currently, the DAM bidding deadline is set at 12:00 p.m. on the day before the operating day. Under the ISO's proposal, DAM offers and bids would be due by 9:00 a.m. on the day before the operating day, the Re-Offer Period would begin at 12:30 p.m. when the DAM schedule is posted and would end 30 minutes later at 13:00, and the initial RAA for the operating day would be completed by 16:00. The ISO believes that these timing changes will allow earlier commitment of long lead-time resources and allow Participants with gas-fired resources to learn their next-day commitments earlier so that they are able to procure gas based on those commitments.

At its December 11-12, 2012 meeting, the Markets Committee considered these proposed changes and voted on (i) the ISO's proposed revisions as modified by a Participant amendment described in further detail below (the "Participant Proposal"), and (ii) the ISO's unamended proposal (the "ISO Proposal"). *See* Attachments A and B, respectively. A copy of the December 13, 2012 Notice of Actions of the Markets Committee detailing these votes, including amendments proposed at, but not supported by, the Markets Committee, is also included with this memorandum as Attachment C.

The Markets Committee recommended Participants Committee support for the Participant Proposal with a 84.8% Vote in favor. This Participant Proposal contains an amendment, offered by Exelon, which revises the ISO-proposed DAM and RAA timelines. Under the Exelon amendment, the DAM bidding deadline would be set at 10:00 on the day before the operating day, the Re-Offer Period from 13:30 to 14:00, and the initial RAA for the operating day would be completed by 17:00. That amendment was recommended by the Markets Committee, with a 70.55% Vote in favor, but was not acceptable to the ISO and not included in the ISO Proposal ("Vote 2" in the Notice of Actions). Following the vote on the amended main motion (i.e., the Participant Proposal), the ISO requested Markets Committee action on its unamended proposal (i.e., the ISO Proposal). The ISO Proposal failed to garner the requisite 60% Vote threshold required for a Markets Committee recommendation, with a 43.05% Vote in favor.

Since the Participant Proposal is the only proposal recommended by the Markets Committee, Participants Committee consideration of proposed revisions to the DAM and RAA timelines will begin with the Participant Proposal. However, because the ISO has indicated that it finds the Participant Proposal to be unacceptable, it is likely that the Participants Committee will also be asked to vote on the ISO Proposal (with any further changes agreed to by the ISO).[1] Please note that if the Participants Committee's votes on these proposals results in a similar outcome to that of the Markets Committee, any related changes to the Market Rules will be subject to a "jump ball" filing.[2]

<u>Potential Motions to Amend the Participant Proposal</u>

The following three additional amendments voted on by the Markets Committee did not pass, but may also be presented for consideration by the Participants Committee at its January 4 meeting:

A. *Vitol Amendment*

This amendment, offered by Vitol, would set the DAM bidding deadline at 10:30, the Re-Offer Period from 14:00 to 14:30, and the initial RAA would be completed by 17:30 ("Vote 1" in the Notice of Actions). *See* Attachment D.

B. *EquiPower Amendment*

The EquiPower amendment would set the DAM bidding deadline at 5:00, the Re-Offer Period from 8:30 to 9:30, and the initial RAA would be completed by 12:00 ("Vote 4" in the Notice of Actions.) *See* Attachment E.

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[1] The ISO is entitled to have a vote on its proposal under Section 11.1.3 of the Participants Agreement if its proposal is modified in a way that it does not support with only those changes it does find acceptable, even if an alternative proposal has already passed.

[2] A "jump ball" gives NEPOOL the right to have NEPOOL proposals for changes to Market Rules considered by the Commission on equal footing with any ISO-proposed Market Rule change when such NEPOOL proposals have 60% or more support of NEPOOL. Section 11.1.5 of the Participants Agreement contains the "jump ball" provisions and states: "If the Participants Committee vote relating to an ISO Market Rule proposal results in the approval by the Participants Committee by a Participants Vote equal to or greater than 60% of a Market Rule proposal that is different from the one proposed by ISO, including, but not limited to, a Governance Participant proposal, ISO shall, as part of any required Section 205 filing, describe the alternate Market Rule proposal in detail sufficient to permit reasonable review by the Commission, explain ISO's reasons for not adopting the proposal, and provide an explanation as to why ISO believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission will not be required to consider whether the then-existing filed rate is unlawful, and may adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable."

C. *Brookfield Amendment*

This amendment may also be presented for Participants Committee consideration. The Brookfield amendment would simply ensure that the Re-Offer Period would last at least one hour (both the Participant Proposal and ISO Proposal include a 30-minute Re-Offer Period). *See* Attachment F. This amendment ("Vote 3" in the Notice of Actions) did not achieve Markets Committee support.

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

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

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Section I.2.2 (Definitions), and the deletion of Appendix H to Market Rule 1, as recommended by the Markets 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 the Chair and Vice-Chair of the Markets Committee may approve; and
>
> FURTHER RESOLVED, that the Participants Committee authorizes and instructs NEPOOL Counsel, in consultation with the NEPOOL Officers, to assemble, prepare and include in filings with the Federal Energy Regulatory Commission such supporting materials (including, if and as appropriate, expert testimony) to support the Market Rule changes if passage of this motion results in a jump ball filing under Section 11.1.5 of the Participants Agreement.

Participant Proposal (sponsored by Exelon)

SECTION I – GENERAL TERMS AND CONDITIONS

I.2.2. Definitions:

Reference Level is defined in Section III.A.~~5.6.1~~7 of Appendix A of Market Rule 1.

Re-Offer Period is the period that normally occurs between the posting of the Day-Ahead Energy Market results and ~~10:00~~2:00 ~~p~~p.m. ~~16:00 and 18:00~~ 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.

SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

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

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

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

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

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

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. ~~12:00 noon~~ on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the ~~re-offer period~~Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

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

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

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $0.0/MWh; and

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to $1,000/MWh.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand

Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may be revised to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its minimum run time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's minimum run time; and

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A

Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

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

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

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

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

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

III.1.10.7 External Transactions.

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

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

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

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

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

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

(ii) FCA Cleared Export Transactions:

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

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

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

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

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

(iii) Same Reserve Zone Export Transactions:

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

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

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

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

(iv) Unconstrained Export Transactions:

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

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

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

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

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

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

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

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

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

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

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

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

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

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England

Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than ~~4:00~~1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource ~~re-offer period~~Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until ~~1:00~~2:00 p.m. ~~4:00 p.m. to 6:00 p.m.~~ on the day before each Operating Day or such other ~~re-offer period~~Re-Offer Period as necessary to account for software failures or other events. During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the

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~~re-offer period~~Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than ~~60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to~~ 20 minutes prior to the hour~~, when the ISO has notified the Market Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period),~~ as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

(c) During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the ~~re-offer period~~Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the ~~re-offer period~~Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect.

(d) **[Reserved.]**

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output levels as practical, consistent with Accepted Electric Industry Practice.

(e) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource's notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead

Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with good utility practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply

Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

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 ~~noon~~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.

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources.

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, ~~and~~ 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. Market Participant requests to alter a Reference Level must be submitted to imm@iso-ne.com.

III.A.3.1. Consultation ~~Prior to Offer~~.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor no later than 90 minutes after the submission deadline for ~~at least one hour prior to the close of~~ the Day-Ahead Energy Market ~~offer deadline~~. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period ~~of the Real-Time Energy Market,~~ the Market Participant must contact the Internal Market Monitor no later than 30 minutes after ~~at least one hour prior to~~ the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by ~~5:00 p.m.~~6:00 p.m. the day prior to the Operating Day. 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

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conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. A Market Participant request pursuant to this section must be submitted to imm@iso-ne.com.

~~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.~~

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 least cost fuel type in the calculation of cost-based Reference Levels pursuant to Section III.A.7.5 below. If a Market Participant requests that the Internal Market Monitor use a higher cost fuel type in the calculation of the cost-based Reference Level, then it must provide the Internal Market Monitor written verification as to the cause for the use of the higher cost fuel and expected duration of such use. The verification as to cause must include a statement as to how the use of the higher cost fuel is consistent with ensuring the availability of the Resource.

In the event that:

(a) the lower cost fuel becomes physically unavailable after the offer deadline for the Operating Day;
(b) the offer for the Operating Day is at or below the Reference Level based on the higher cost fuel, and;
(c) the Market Participant notifies the Internal Market Monitor; then

the Internal Market Monitor shall evaluate the information provided by the Market Participant. If the Internal Market Monitor determines that the Reference Level should be based on the more expensive fuel, the Internal Market Monitor may apply a Reference Level based on the more expensive fuel, or treat the offer as not violating applicable conduct tests for the Operating Day for which the offer is submitted. At the time of notification, the Market Participant shall provide all available documentation showing why the Resource must use the higher-priced fuel, such as a fuel supplier notice of the interruption. Within five business days of the Operating Day, if not already made available to the Internal Market Monitor during the initial notification, the Market Participant shall provide full documentation regarding the use of the higher-priced fuel, including evidence that the higher priced fuel was used or, alternatively, of the lack of energy generated, as well as evidence of the fuel interruption.

If the Market Participant fails to provide supporting information within five business days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes. Market Participant requests and supporting information must be submitted to imm@iso-ne.com.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. The Reference Levels will be made available on a daily basis. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

NCPC ACCOUNTING

III.F.1. Overview.

Accounting for the provision of Operating Reserve and Replacement Reserve is performed on a daily basis. A generating Resource of a Market Participant that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Day-Ahead Energy Market subject to limitations when the Supply Offer includes Self-Scheduled hours as discussed in Section III.F.1.1.1. A generating Resource of a Market Participant, including a Local Second Contingency Protection Resource, that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Real-Time Energy Market provided that the Resource satisfies the criteria specified in Sections III.F.1.1.2 and III.F.2.1.7 below.

NCPC Credits are also provided for dispatchable External Transactions (both purchases and sales), for Increment Offers and Decrement Bids at External Nodes, for generating units operating as Synchronous Condensers at the direction of the ISO, for Dispatchable Asset Related Demand Resources (pumps only) that are not Self-Scheduled, for cancellation of generating Resources that are Pool-Scheduled Resources and for generating units backed down for the purposes of providing Operating Reserve or VAR support. NCPC calculations shall be performed separately for the Day-Ahead and Real-Time Energy Markets.

III.F.1.1. Effect of Self-Schedules on NCPC Credits

III.F.1.1.1 Ineligibility for NCPC Credits (Day-Ahead Energy Market).

In the Day-Ahead Energy Market, the Resource's Self-Scheduled hours shall be the Self-Scheduled hours submitted in the Supply Offer.

(a) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation, a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains two blocks of contiguous Self-Scheduled hours separated by less than the Resource's minimum down time. For purposes of this calculation, a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days, or crosses the boundary between two Operating Days as described in (a) above, and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of non Self-Scheduled hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

III.F.1.1.2 Ineligibility for NCPC Credits (Real-Time Energy Market).
In the Real-Time Energy Market, the Self-Scheduled hours for the purpose of determining NCPC Credit eligibility shall be the Self-Scheduled hours from the Day-Ahead Schedule as modified in the Re-Offer ~~electronic bidding~~Period ~~as described in Market Rule I Section III.1.10.9(a)~~ ~~(the Real-Time schedule as of 18:00 hours of the day prior to the Operating Day)~~, including any redeclaration of Self-Scheduled hours by a Market Participant pursuant to Section 8 of ISO New England Manual-11.

(a) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if its Supply Offer (submitted either in the Day-Ahead Energy Market or during the Re-Offer Period) contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if it submits (as a Supply Offer in the Day-Ahead Energy Market or during the Re-Offer Period) two Self-Schedules separated by less than the Resource's minimum down time. For purposes of this calculation a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first Operating Day as meeting the minimum down time requirement but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days or crosses the boundary between two Operating Days and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

(e) For purposes of the above determinations, the minimum run time portion of a Real-Time Commitment Period commences with the first hour of the Real-Time Commitment Period in which the actual metered output of the generating Resource equals or exceeds 75 percent of the generating Resource's Economic Minimum Limit; provided that, if the Resource is a Fast Start Generator that never reaches 75 percent of its Economic Minimum Limit during its Real-Time Commitment Period, its minimum run time will commence with the first hour in which it has positive output. Each Real-Time Commitment Period is evaluated separately for the purpose of determining NCPC Credit eligibility.

The Real-Time NCPC Credit eligibility criteria set forth in subsections (a) through (e), above, shall be waived for additional hours of operation that result from an ISO request for extension of the Resource's operating schedule.

III.F.2. NCPC Credits.

NCPC Credits are calculated for each of the following situations:

(1) Pool-Scheduled Resources (Generators), including Local Second Contingency Protection Resources (Generators) and External Transactions (Day-Ahead and Real-Time Energy Markets); Increment Offers and Decrement Bids cleared at External Nodes.

(2) Pool-Scheduled Resources (Synchronous Condensers and Special Constraint Resources ("SCR") - Real-Time Energy Market)

(3) Canceled Pool-Scheduled Resources (Real-Time Energy Market)

(4) Resources postured for reliability purposes (Real-Time Energy Market)

(5) Dispatchable Asset Related Demand Resources (pumps only) that are postured for reliability purposes in Real-Time.

(6) Self-Scheduled generating Resources providing Operating Reserves by operating in accordance with Dispatch Instructions in non-Self-Scheduled hours or at levels above the Self-Scheduled MW in Self-Scheduled hours during an Operating Day in which they have offered a contiguous block of Self-Scheduled hours, which meet the criteria for such Self-Schedules set forth in Section III.F.1, at least equal to their minimum run times.

III.F.2.1. Credits for Generating Resources.

For each Operating Day, the ISO calculates the NCPC Credit due each Market Participant for generating Resources.

In the Day-Ahead Energy Market, eligible generating Resources shall receive Day-Ahead NCPC Credits for all hours that are not Self-Scheduled. Except as otherwise provided in this Appendix F, all eligible generating Resources are eligible except generating Resources that have Self-Scheduled hours that do not meet the criteria set forth in Section III.F.1.1.1 are ineligible for Day-Ahead NCPC Credit. For purposes of the Day-Ahead NCPC Credit calculations, the Self-Scheduled hours shall be the Self-Scheduled hours in the Participant's Supply Offer.

In the Real-Time Energy Market, an eligible generating Resource is eligible to receive Real-Time NCPC Credits for all hours that are not Self-Scheduled and for MW amounts in excess of the Self-Scheduled MW for Self-Scheduled hours when the Resource operates above the Self-Scheduled MWs at the ISO's request. A generating Resource is not eligible to receive Real-Time NCPC Credits for any hour in which the Resource is ramping up from an off-line state prior to being released for dispatch, or ramping down after receiving a shutdown order. Self-Scheduled hours include hours when the Resource is ramping up to a Self-Scheduled hour from an off-line state, or down from a Self-Scheduled hour to an offline state and hours when the Resource is Self-Scheduled for Regulation. Eligible generating Resources shall consist of Pool-Scheduled Resources and Self-Scheduled Resources that meet the criteria in Section III.F.1.1.2 and any generating Resources specifically made eligible for Real-Time NCPC Credits in other Sections of this Market Rule 1.

III.F.2.1.1 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

III.F.2.1.2 Hourly Day-Ahead Offer Amount.

The ISO calculates the generating Resource's hourly Day-Ahead offer amount based on its Day-Ahead Offer Data that was utilized by the ISO in making the initial commitment decision and the generating Resource's cleared Day-Ahead MWh for that hour.

For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

(a) The ISO accounting process applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Resource Offer Data and if the Start-Up Fee is applicable for the MWh and status of the Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource Day-Ahead and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant. The Start-Up Fee will be associated with the first hour of the Resource's minimum run time on the day for which the Resource is committed. The Start-Up Fee will always be on the same Operating Day for both the Day-Ahead and Real-Time Energy Markets for purposes of calculating Real-Time NCPC Charges/Credits.

(b) Day-Ahead NCPC Credit calculations reflect the Start-Up Fee for the appropriate hot, intermediate, or cold state of the generating unit as it was scheduled in the Day-Ahead Energy Market.

III.F.2.1.3 Hourly Day-Ahead Value.

The ISO *calculates* the generating Resource's hourly Day-Ahead value as: generating Resource cleared Day-Ahead MWh * Day-Ahead LMP

III.F.2.1.4 Daily Day-Ahead Credit.

The ISO calculates the daily Day-Ahead credit for each generating Resource as follows:

(a) Sum hourly Day-Ahead offer amounts, including applicable No-Load Fees and Start-Up Fees, for the day.

(b) Sum hourly Day-Ahead values for the day.

(c) Day-Ahead credit equals any portion of the generating Resource's total Day-Ahead offer amount in excess of its total Day-Ahead value.

III.F.2.1.5 Day-Ahead Credit Allocation.

The ISO allocates the Day-Ahead credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource was scheduled and was eligible for NCPC Credit pro-rata based on Day-Ahead Load Obligations as follows:

Hourly Credit = Daily Credit * (Day-Ahead Load Obligations in scheduled hour) / (Total Day-Ahead Load Obligations in all scheduled hours))

[Note: Each credit is allocated back retaining its flag (Local Second Contingency Protection Resource, VAR etc.)]

III.F.2.1.6 Day-Ahead NCPC Credit: Hourly Market Participant Credit; Operating Day Total.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credit and the total Day-Ahead NCPC Credit for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset.

(b) For each scheduled hour, if the generating Resource is flagged specifically for the provision of VAR or voltage support, the Market Participant's share of Day-Ahead VAR credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits for all generating Resources for that Operating Day.

(c) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead VAR credits is equal to 50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits and all Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day.

(d) For each scheduled hour, if the generating Resource is not flagged as a Local Contingency Protection Resource or VAR, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.7 Real-Time NCPC Credit Eligibility.

The ISO determines eligibility for Real-Time NCPC Credits. The following operating guidelines are used in the determination of Real-Time NCPC Credit eligibility:

(a) Generating Resources must be following Dispatch Instructions. For any hour that the generating Resource is not following Dispatch Instructions and the difference between the generating Resource's energy value, in dollars, and energy offer amount, in dollars, (in this case, energy offer amount includes No-Load Fee and incremental energy price and does not include any Start-Up Fee) in that hour is negative, the generating Resource's energy offer amount, in dollars, and energy value, in dollars, in that hour is excluded from the Real-Time NCPC Credit calculations.

(b) Generating Resources that trip during their Real-Time Commitment Periods are treated as set forth below:

(i) If the generating Resource trips during its minimum run time period and the generating Resource is otherwise eligible to receive Real-Time NCPC Credit, the Resource will be eligible for Real-Time NCPC Credit for the period beginning with the start of the Real-Time Commitment Period and ending at the time of the trip. For purposes of determining such generating Resource's eligibility for Real-Time NCPC Credit, such generating Resource shall be eligible to recover a portion of its Start-Up Fee equal to the applicable Start-Up Fee multiplied by the quotient (not to exceed 1) of the generating Resource's hours of operation during the current Real-Time Commitment Period and the generating Resource's minimum run time (Start-Up Fee* (Hours of operation/minimum run time)).

(ii) If the generating Resource trips after its minimum run time has been satisfied and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource will be eligible to receive Real-Time NCPC Credit for hours that were not Self-Scheduled during that Real-Time Commitment Period.

(iii) If the generating Resource trips, is requested to restart by the ISO, and returns to operate as requested, and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource is eligible to receive Real-Time NCPC Credits (including Start-Up Fee, No-Load Fee and incremental Energy price) for the new Real-Time Commitment Period.

(iv) Generating Resources that trip and return to operate that are not requested to restart by the ISO are treated as Self-Scheduled Resources and are not eligible for Real-Time NCPC Credits (Start-Up Fees and No Load Fee) for the new Real-Time Commitment Period.

When a generating Resource trips off line as the result of an equipment failure that involves equipment located on the electric network beyond the low voltage terminals of the generating unit step-up transformer, the ISO shall not treat the event as a trip for the purposes of determining the generating Resource's eligibility for Real-Time NCPC Credit for that Real-Time Commitment Period. It is the responsibility of the Lead Market Participant for the generating Resource to inform the ISO at xtrip@iso-ne.com within thirty (30) days that the trip was the result of such a transmission-related event.

(c) If a generating Pool-Scheduled Resource is otherwise eligible to receive Real-Time NCPC Credit and waives its minimum run time at the ISO's request, or if the ISO accepts an offer from a generating

Pool-Scheduled Resource that is otherwise eligible to receive Real-Time NCPC Credit to waive its minimum run time and the ISO agrees to allow the Resource to shut down prior to completion of the generating Pool-Scheduled Resource's minimum run time:

(i) The generating Pool-Scheduled Resource shall be considered to have completed its minimum run time in calculating Real-Time NCPC Credits for which the generating Pool-Scheduled Resource is otherwise eligible; and

(ii) The generating Pool-Scheduled Resource's applicable Start-Up Fee shall be included in the calculation of said NCPC Credits.

III.F.2.1.8 Hourly Real-Time MWh.

The ISO determines the generating Resource's hourly Real-Time MWh based on the values submitted to the ISO by the Assigned Meter Reader for that hour.

III.F.2.1.9 Hourly Real-Time Energy Offer Amount.

The ISO calculates the generating Resource's hourly Real-Time energy offer amount based on its prices contained in the Supply Offer (if said Supply Offer has been mitigated, the mitigated Supply Offer shall be used for this calculation) for all eligible hours. For pool-scheduled hours, the Supply Offer price is multiplied by the lesser of the generating Resource's Desired Dispatch Point (provided that any Desired Dispatch Point below the Resource's Economic Minimum Limit will be deemed equal to the Economic Minimum Limit) or its actual metered output for that hour less the Resource's cleared Day-Ahead MWh. For generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours, the Supply Offer price (excluding the Start-Up Fees and No-Load Fee) is multiplied by the lesser of the DDP or actual metered quantity less the greater of the Resource's Self-Scheduled MW or the Resource's cleared Day-Ahead MWh. Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the output of the unit that is attributable to its submittal of a Self-Schedule for Regulation. For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

III.F.2.1.10 Application of Start-Up Fee and Hourly No-Load Fee.

The ISO applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Generator Offer Data and if the Start-Up Fee is applicable for the MWh and status of the generating Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource in Real-Time and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant or if that Participant's Resource was scheduled in the Day-Ahead Energy Market. The No-Load Fee is not applicable in any hour if the total number of hours that the Resource cleared in the Day-Ahead Energy Market is greater than the total number of hours that the Resource had actual generation greater than zero. If the total number of hours that the Resource had actual generation greater than zero is greater than the total number of hours that the Resource cleared in the Day-Ahead Energy Market, the No-Load Fees would be applicable once the total number of hours that the Resource actually ran in Real-Time exceeded the total number of hours that the Resource cleared in the Day-Ahead Energy Market.

III.F.2.1.11

If applicable, when a generating Resource is started during the day at the direction of the ISO, the generating Resource's Real-Time offer amount calculated for that day includes its Start-Up Fee based on the appropriate hot, intermediate, or cold state of the generating Resource. For generating Resources that start generating for the ISO from a condensing state, the applicable Start-Up Fee for that generating Resource shall be the Start-Up Fee submitted that is associated with the hot state of the unit.

III.F.2.1.12

If applicable, the generating Resource's Real-Time calculated offer amount includes its hourly No-Load Fee prorated for all hours of operation as follows, using a 10% tolerance:

> If: lesser of (Real-Time MWh or Desired MW) < .9 * (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time),
> Then: hourly No-Load Fee is prorated by (lesser of (Real-Time MWh or Desired MW) / (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time).

III.F.2.1.13 Generating Resource Hourly Real-Time Value.

The ISO calculates the generating Resource's hourly Real-Time value for all eligible hours as:

((generating Resource metered value – max (generating Resource cleared Day-Ahead MWh, generating Resource Real-Time Self-Schedule MWh)) * (Real-Time LMP at generating Resource Node)) + generating Resource Regulation Opportunity Cost.

III.F.2.1.14 Generating Resource Daily Real-Time Credits.

The ISO calculates the daily Real-Time credits for each generating Resource as follows:

(a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day.

(b) Sum hourly Real-Time values for the day.

(c) Real-Time credits are equal to any portion of the generating Resource's total Real-Time offer amount in excess of its total Real-Time value.

III.F.2.1.15 Real-Time Credit Allocation.

The ISO allocates the Real-Time credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource actually operated and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * (Real-Time Load Obligation in operating hour) / Total Real-Time Load Obligations in all operating hours)

III.F.2.1.16 Real-Time NCPC Credits; Hourly Market Participant Credit; Operating Day Total.

The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as providing Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time SCR NCPC Credits for all generating Resources for that Operating Day,

(b) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(c) For each scheduled hour, if the generating Resource is flagged as a VAR Generator, the Market Participant's share of Real-Time VAR credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits for all generating Resources for that Operating Day,

(d) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time VAR credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits and all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(e) For each scheduled hour, if the generating Resource is not flagged as a Local Second Contingency Protection Resource or VAR, the Market Participant's share of Real-Time economic NCPC Credit is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.17 Addition of Hourly Shortfall Payments.

Generating Resources that are Pool-Scheduled Resources in the Day-Ahead Energy Market that are available, can deliver Energy and are not Postured, but are not economically dispatched in Real-Time and have not changed their incremental energy offers during the ~~re-offer period~~Re-Offer Period, are eligible to receive the difference between the Real-Time and Day-Ahead LMP at the generator bus times the Day-Ahead scheduled MWh for hours when the Real-Time LMP is greater than the Day-Ahead LMP. Any payments made for each hourly shortfall are added to the total Real-Time economic NCPC Credits, Real-Time Local Second Contingency Protection Resource NCPC Credits or Real-Time VAR credits, as applicable, for the applicable Operating Day.

III.F.2.1.18 Addition of Minimum Generation Emergency Credits.

When a Minimum Generation Emergency has been declared (see Section 2.5.13.2 of ISO New England Manual M-11), generating Resources that are otherwise eligible to receive Real-Time NCPC Credits may be eligible to receive Minimum Generation Emergency Credits as provided below:

(a) Minimum Generation Emergency Credits will only be available in the Data Reconciliation Resettlement of the monthly services customer bill for the Operating Day(s) in which the Minimum Generation Emergency was declared.

(b) Minimum Generation Emergency Credits must be requested by sending a letter to the ISO's Market Support Services Department (custserv@iso-ne.com) within 20 business days after issuance of the monthly services customer bill that covers the hours of Minimum Generation Emergency for which a claim is being made. Requests received later than 20 business days after the issuance of the monthly services customer bill that includes the Minimum Generation Emergency hours for which a claim is being made will not be accepted.

(c) The lesser of the generating Resource's Desired Dispatch Point or actual metered output must be above the generating Resource's Economic Minimum Limit for each hour for which Minimum Generation Emergency Credit is requested.

(d) The Minimum Generation Emergency Credit for each eligible hour will be calculated as follows:

(i) The generating Resource's Economic Minimum Limit will be subtracted from the lesser of the generating Resource's Desired Dispatch Point ("DDP") or Real-Time Generation Obligation. Generating Resources with DDPs above Economic Minimum Limits because they are ramp rate constrained when being dispatched down to their Emergency Minimum Limits will have the result of the above calculation set to zero.

(ii) The result of step (i) will be multiplied by the Supply Offer price (in this case excluding the daily Start-Up Fee but not the hourly No-Load Fee) associated with the appropriate Supply Offer Energy block

(iii) The result of step (ii) will be reduced by any revenue received during that hour in the Real-Time Energy Market due to a non-zero LMP for the hour(s) for which the Minimum Generation Emergency was declared.

(e) Resources receiving Minimum Generation Emergency Credits under this Section III.F.2.1.18 shall be ineligible to receive Real-Time NCPC Credit for the same hour(s).
Charges associated with Minimum Generation Emergency Credits are discussed in Section 3 of this Appendix F.

III.F.2.2. Real-Time Credits for Pool-Scheduled Synchronous Condensers.
For each Operating Day, the ISO calculates the NCPC Credits due each Market Participant for Pool-Scheduled Resources scheduled as Synchronous Condensers.

III.F.2.2.1 Information Retrieved.
The ISO retrieves the following information:

(a) Dispatcher generation scheduling and operations logs

(b) Generator Offer Data

III.F.2.2.2 Duration of Pool-scheduled Periods of Synchronous Condensing Operations.
The ISO calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.

III.F.2.2.3 Condensing Offer Amount.
The ISO calculates each generating Resource's condensing offer amount for each period by multiplying the duration (in hours) by the hourly price to condense as specified in the Offer Data. If no hourly price to condense is listed in the Generator Offer Data, an hourly price of zero will be assumed and no payment will be made.

III.F.2.2.4 Condensing Credit.

When a generating Resource is requested to start condensing from an off-line state, a condensing credit is provided equal to the Resource's condensing Start-Up Fee as specified in the Offer Data.

III.F.2.2.5 VAR Credit.

If a unit is flagged as a VAR Resource and as a Synchronous Condenser, it will be compensated by a VAR credit.

III.F.2.2.6 Market Participant's Real-Time NCPC Condensing Credits.

The ISO calculates the daily Real-Time NCPC condensing credits for each Market Participant by summing all remaining hourly condensing generating Resource offer amounts, including applicable Start-Up Fees, for the Operating Day taking the Market Participant's Ownership Share into account.

III.F.2.2.7 Total Real-Time NCPC Condensing Credits.

The ISO sums the Real-Time NCPC condensing credits for all Market Participants for each Operating Day.

III.F.2.3. Credits for Pool-Scheduled External Transaction Purchases or Increment Offers at External Nodes.

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction purchases (modeled as Supply Offers at External Nodes) or Increment Offers at External Nodes as follows. These calculations only apply to External Transaction purchases submitted that are dispatchable and are submitted as source equals sink, or cleared Increment Offers at External Nodes.

III.F.2.3.1

Real-Time NCPC eligibility for pool-scheduled External Transactions Purchases (priced imports).

(a) For each hour that a pool-scheduled External Transaction purchase is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions purchases are only eligible for Real-Time NCPC Credits to the extent that the Real-Time transaction (measured in MWh) exceeds the associated Day-Ahead schedule.

III.F.2.3.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction purchases, and Increment Offers at External Nodes

(c) hourly pool-scheduled Day-Ahead and Real-Time External Transaction purchase offer price curve ($/MWh, MW), and hourly Increment Offer price curve ($/MWh,MW) submitted at External Nodes

(d) Day-Ahead and Real-Time LMPs

(e) Transaction flags (Local Second Contingency Protection Resource)

III.F.2.3.3 Day-Ahead Offer Amount.

The ISO calculates the hourly Day-Ahead offer amount for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the transaction offer price.

III.F.2.3.4 Hourly Day-Ahead Value.

The ISO calculates the hourly Day-Ahead value for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the Day-Ahead LMP at the applicable External Node.

III.F.2.3.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction purchase or Increment Offer at an External Node as follows:

(a) Day-Ahead offer amounts for the hour

(b) Day-Ahead values for the hour

(c) Day-Ahead NCPC Credits for External Transaction purchases or Increment Offers equal any portion of the import transaction's hourly Day-Ahead offer amount in excess of its hourly Day-Ahead value; provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction purchases or Increment Offers for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction sales or Decrement Bids for the External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the total External Transaction purchases or Increment Offers at the External Node are not offset by those of the total cleared External Transaction sales or Decrement Bids. The External Transaction purchases megawatts will be offset in order from highest to lowest price.

III.F.2.3.6 [Reserved.]

III.F.2.3.7 Day-Ahead NCPC Credits: Market Participant's Hourly Credits.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credits as follows:
For each scheduled hour, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour.

III.F.2.3.8 Hourly Real-Time Offer Amount.

The ISO calculates the hourly Real-Time offer amount for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead schedule by the transaction offer price.

III.F.2.3.9 Hourly Real-Time Value.

The ISO calculates the hourly Real-Time value for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead transaction MWh amount by the Real-Time LMP of the applicable External Node.

III.F.2.3.10 Real-Time Credits Calculation.

The ISO calculates the daily Real-Time credits for Real-Time External Transaction purchases as follows:

(a) Sum hourly Real-Time offer amounts for the day

(b) Sum hourly Real-Time values for the day

(c) Real-Time daily credit equals the portion of the External Transaction purchase's total daily Real-Time offer amount in excess of its daily Real-Time value.

III.F.2.3.11 Real-Time Credits Allocation.
The ISO allocates the Real-Time credits, for each External Transaction purchase for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.3.12 Real-Time NCPC Credits: Market Participant's Hourly and Operating Day Total.
The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the External Transaction purchase is flagged as Local Second Contingency Protection Resource, the Market Participant's share of Local Second Contingency Protection Resource economic NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all External Transaction purchases for that Operating Day,

(b) For each scheduled hour, if the External Transaction purchase is not flagged as Local Second Contingency Protection Resource, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time NCPC Credits for all External Transaction purchases for that Operating Day.

III.F.2.4. Credits for Pool-Scheduled External Transactions Sales or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (Pumps Only).

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction sales (modeled as Demand Bids at External Nodes) or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (pumps only) as follows. Credits for pool-scheduled External Transaction sales or Decrement Bids at External Nodes only apply to External Transaction sales submitted that are Dispatchable and are submitted as source equals sink, or cleared Decrement Bids at External Nodes. Dispatchable Asset Related Demand Resources (pumps only) are eligible for NCPC Credits in hours for which they are not Self-Scheduled and are following Dispatch Instructions. Dispatchable Asset Related Demand Resources (pumps only) that are Self-Scheduled for any portion of an hour shall be considered Self-Scheduled for the entire hour and shall not be eligible for NCPC Credits in that hour.

III.F.2.4.1

Real-Time NCPC Credit eligibility for pool-scheduled External Transactions Sales (priced exports) is determined as follows:

(a) For each hour that a pool-scheduled External Transaction sale is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions sales are only eligible for Real-Time NCPC to the extent that the Real-Time transaction (measured in MWh) is scheduled to consume more than the associated Day-Ahead schedule.

III.F.2.4.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction sales (positive values), and Decrement Bids at External Nodes

(c) Pool-scheduled Day-Ahead scheduled consumption and Real-Time actual consumption for Dispatchable Asset Related Demand Resources (pumps only) (positive values)

(d) hourly pool-scheduled Day-Ahead and Real-Time External Transaction Demand Bid cost curve ($/MWh, MW), and hourly Decrement Bid cost curve ($/MWh,MW) submitted at External Nodes

(e) hourly pool-scheduled Real-Time Demand Bid cost curve ($/MWh, MW) for Dispatchable Asset Related Demand Resources (pumps only)

(f) Day-Ahead and Real-Time LMPs

III.F.2.4.3 Day-Ahead Bid Amount.

The ISO calculates the hourly Day-Ahead bid amount for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Demand Bid price.

III.F.2.4.4 Day-Ahead Cost.

The ISO calculates the hourly Day-Ahead cost for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Day-Ahead LMP at the applicable External Node.

III.F.2.4.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction sale or Decrement Bid at an External Node as follows:

(a) Day-Ahead bid amounts for the hour

(b) Day-Ahead costs for the hour

(c) Day-Ahead NCPC Credits for External Transaction sales or Decrement Bids equal any portion of the sale transaction's hourly Day-Ahead cost in excess of its hourly Day-Ahead bid amount provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction sales or Decrement Bids for a given External Node and hour and the submitting Market

Participant or its Affiliate has also submitted and cleared one or more External Transaction purchases or Increment Offers for the same External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the External Transaction sales or Decrement Bids at the External Node are not offset by those of the total cleared External Transaction purchases or Increment Offers. The External Transaction sales megawatts will be offset in order from lowest to highest price.

III.F.2.4.6 [Reserved.]

III.F.2.4.7 Real-Time Bid Amount - External Transaction Sale.

The ISO calculates the hourly Real-Time bid amount for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the transaction Demand Bid price.

III.F.2.4.8 Real-Time Bid Amount - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time bid amount for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption less any cleared Day-Ahead consumption by the Dispatchable Asset Related Demand Resources (pumps only) Demand Bid price.

III.F.2.4.9 Real-Time Cost - External Transaction Sale.

The ISO calculates the hourly Real-Time cost for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the Real-Time LMP of the applicable External Node.

III.F.2.4.10 Real-Time Cost - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time cost for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption hourly deviations from the cleared Day-Ahead amount by the Real-Time LMP of the applicable Node.

III.F.2.4.11 Real-Time Credits - External Transaction Sale.

The ISO calculates the daily Real-Time NCPC Credits for Real-Time External Transaction sales as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals the portion of the External Transaction sale's total daily Real-Time bid amount that is less than its daily Real-Time cost.

III.F.2.4.12 Real-Time Credits Allocation - External Transaction Sale.

The ISO allocates the Real-Time NCPC Credits, for each External Transaction sale for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.4.13 Real-Time Credits -Dispatchable Asset Related Demand Resources (Pumps Only).
The ISO calculates the daily Real-Time NCPC Credits for Real-Time Dispatchable Asset Related Demand Resources (pumps only) as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals any portion of total daily Real-Time costs in excess of its total daily Real-Time bid amount of the Dispatchable Asset Related Demand Resource (pumps only).

III.F.2.4.14 Real-Time Credits Allocation -Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO allocates the Real-Time NCPC Credits, for each Dispatchable Asset Related Demand Resources (pumps only) for each Operating Day, back to each hour in the Operating Day in which the Dispatchable Asset Related Demand Resources (pumps only) was scheduled as follows:
Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.5. Credits for Canceled Pool-Scheduled Resources (Generators).
For each Operating Day, the ISO calculates an NCPC Credit for the cancellation of a start-up prior to the assigned commitment time for any generating Pool-Scheduled Resource that:

(a) Was not scheduled by the ISO in the Day-Ahead Energy Market, and

(b) Was issued Dispatch Instructions to start-up in Real-Time. This cancellation credit is based on values submitted by Market Participants as part of the Resource's Offer Data. The following Offer Data parameters are utilized in the calculation: hot to cold time, hot to inter time, hot startup cost, inter startup cost, cold startup cost, hot notification time, inter notification time, and cold notification time.

III.F.2.5.1 Information Retrieved.
The ISO retrieves the following information:

(a) list of canceled generating Resources (dispatcher log)

(b) Applicable generator Start-Up Fee (hot startup cost, inter startup cost or cold startup cost)

(c) Generator flags (Local Second Contingency Protection Resource, VAR, or SCR)

(d) generation data

III.F.2.5.2 Cancelled Start Credit Calculation.
The ISO credits each Market Participant for cancellation based on a pro-rata share of the applicable generating Resource's Start-Up Fee, and associated notification time parameter (hot, inter, or cold) utilized by the ISO in the original commitment decision. The credit for cancelled starts is calculated as follows:

Cancelled Start Credit = Applicable Generator Start-Up Fee * (1- ((Cancel Time) /(Notification Time))),

Where,

Applicable Generator Start-Up Fee	equals (i) Hot Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is less than the Hot to Inter Time; (ii) Inter Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Inter Time and less than the Hot to Cold Time; or (iii) Cold Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Cold Time,
Cancel Time	equals the difference, in hours, between the original ISO Commitment Order Time for the unit and the time at which the ISO cancelled the commitment of the unit. Cancel Time must be less than or equal to Notification Time, otherwise, the Cancelled Start Credit is set equal to zero,
ISO Commitment Order Time	equals the time at which the unit was originally requested to be synchronized to the New England Transmission system,
Notification Time	equals the applicable number of hours required to synchronize the unit to the system as submitted as part of the Generating Resource's Offer Data (Hot Notification Time, Intern Notification Time, or Cold Notification Time), and

Cancelled Start Credit is limited to be no greater than the applicable Start-Up Fee and notification time cannot be longer than 24 hours.

III.F.2.5.3 Real-Time NCPC Credit.

The Real-Time NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in Section III.F.2.5.2 above for all generating Pool-Scheduled Resources that were not originally flagged as a Local Second Contingency Protection Resource or VAR.

III.F.2.5.4 Local Second Contingency Protection Resource NCPC Credit.

The Real-Time Local Second Contingency Protection Resource NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.1.13 above for all generating Pool-Scheduled Resources that were originally flagged as Local Second Contingency Protection Resources.

III.F.2.5.5 VAR Credit.

The Real-Time VAR credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.5.2 above for all generating Pool-Scheduled Resources that were originally flagged as VAR.

III.F.2.5.6 Reserved.

III.F.2.5.7 SCR Credits.

The Real-Time SCR credits associated with generating units identified as SCR Resources are billed as provided for in Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.F.2.5.8 Example.

An example of the cancelled start calculation is as follows:

> Asset ID ABC was scheduled after the close of the Day-Ahead Energy Market to start at 6:00 am. ISO Cancelled the unit Start Time, in Real-Time, at 4:00 am. Cancel Time Column is calculated by subtracting Start time – Cancel time (6 – 4 = Cancel Time is 2)
> To determine the amount Cancelled Start we look at the Start-Up Fee and we multiply it by 1 minus Cancel Time divided by Time to Start.

III.F.2.6. Credits for Generating Resources and Dispatchable Asset Related Demand Resources (pumps only) Postured for Reliability.

The ISO credits Dispatchable Asset Related Demand Resources (pumps only) for responding to the ISO's request to increase consumption to a level above what would have been consumed during normal economic operation. The ISO credits Postured generating Resources, both pool-scheduled and Self-Scheduled, for responding to the ISO's request to reduce or suspend normal economic operation. A Resource shall be considered postured when it meets the conditions described in the definition of "Postured" in the Tariff. The ISO takes into account any generator Regulation credits associated with the postured generating Resource for the provision of Regulation while postured in calculating the posturing credits for generating Resources. For a Dispatchable Asset Related Demand Resource (pumps only) that is Postured, the posturing credits are calculated in accordance with Section III.F.2.4.

III.F.2.6.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)

(b) Generator Offer Data

(c) 5 minute generation data from EMS

(d) Real-Time LMP data

(e) Real-Time Generation Obligation

(f) Generator Regulation credits

III.F.2.6.2 Posturing Credit Calculation.

The ISO credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Daily Energy Restrictions.* For generating Resources without energy restrictions, the posturing credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – GRC

Where

PAG equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;

AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
UB	equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
GRC	(Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Daily Energy Restrictions.* For generating Resources with energy restrictions, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the hour that posturing began and ending at the end of the calendar day,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP - UB) – GRC

Where:

PAG	equals the estimated hourly generation had the generating Resource not responded to Dispatch orders to reduce or suspend operation. Estimated operation for generating Resources following the Day-Ahead schedule prior to the posturing event will be determined by the Day-Ahead schedule. From the start of the posturing event through the end of the calendar day, PAG is set to the Day-Ahead schedule for as long as available energy would have supported the operation. For generating Resources responding to DDP's in Real-Time or operating under Real-Time Self-Schedule changes prior to the posturing event, PAG will be set assuming economic operation would have occurred during posturing and throughout the day for as long as the available energy would have supported the operation;
AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource;
UB	equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4 of the ISO New England Manual for Market Rule 1 Accounting, M-28.

(c) *Generating Resources With Weekly Energy Restrictions*. For generating Resources with weekly energy restrictions, credits are determined based on an estimate of the net opportunity cost in the energy market for the week. The net amount of a posturing credit shall not be negative.

Posturing credits for Resources with weekly energy restrictions are calculated as follows:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the first hour in the period in which a Resource is postured through the end of the weekly energy restriction period,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP-UB) – GRC

Where:

For an hour during which the Resource was postured, PAG equals the estimated hourly generation had the generating Resource not responded to Dispatch Instructions to reduce or suspend operation. For an hour in which the Resource was not postured, PAG equals the actual generation of the Resource. Once the total energy available for use during the weekly energy restriction period has between fully consumed by the estimated economic dispatch while postured plus actual generation while not postured, PAG equals zero; AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource;

UB equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4.2 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP – UB shall not be negative.

For postured resource with weekly energy restrictions, the credits and charges will be calculated for the weekly energy restriction period.

This subsection (c) shall be effective through September 30, 2012.

III.F.2.6.3 Real Time NCPC Credits.

The Real-Time NCPC Credits for posturing for the Operating Day are equal to the sum of the non-VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.4 Real Time VAR Credits.

The Real-Time VAR credits for posturing for the Operating Day are equal to the sum of the VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.5 Real Time NCPC Credits – Weekly Posturing.

The Real-Time NCPC Credits for Posturing for a Resource with weekly energy restrictions, as described in Section III.F.2.6.2(c), are equal to the sum of the non-VAR related Real-Time Posturing credits associated with restricting the output of a generating Resource for the weekly energy restriction period.

This Section III.F.2.6.5 shall be effective through September 30, 2012.

III.F.3. Charges for NCPC

III.F.3.1. Allocation.

The sum of Day-Ahead NCPC Credits for the Day-Ahead Energy Market, excluding the Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes, is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time NCPC Credits (excluding Posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Asset Related Demand Resources that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Asset Related Demand Resources for the Operating Day that result from operation in accordance with the ISO ’s instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic Minimum Limit. Real Time NCPC Credits associated with the Posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit.

The sum of Day-Ahead Local Second Contingency Protection Resource NCPC Credits associated with generating Resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region in proportion to the daily sum of their Day-Ahead Load Obligations within each affected Reliability Region. The sum of Real-Time Local Second Contingency Protection Resource NCPC Credits associated with generating units identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region and, under certain circumstances, to any adjacent Control Area purchasing Emergency energy from the ISO. Charges are allocated in proportion to the daily sum of Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) Operation that is above its Minimum Consumption Limit) plus applicable Emergency energy sales within each affected Reliability Region.

The sum of Day-Ahead and Real-Time NCPC Credits paid to Market Participants associated with Resources other than SCRs (including Synchronous Condensers and Postured Resources) that have been identified by the ISO as being required to provide voltage support or VAR support are collected from Market Participants in accordance with Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Each Market Participant's Minimum Generation Emergency Charge is calculated as follows:

(1) For each generating Resource of the Market Participant for which a Minimum Generation Emergency Credit is calculated, subtract the Resource's Economic Minimum Limit from its Real-Time Generation Obligation and then multiply the result by the Market Participant's Ownership Share in the Resource. The sum of the results of such calculations shall be that Market Participant's Exempt Real-Time Generation Obligation.

(2) Subtract the sum of the Exempt Real-Time Generation Obligations for all Market Participants from the total Real-Time Generation Obligation of all Market Participants at Locations within the Reliability Region(s) for which a Minimum Generation Emergency was declared.

(3) Subtract the Market Participant's Exempt Real-Time Generation Obligation, as calculated in step (1) above, from its total Real-Time Generation Obligation within the Reliability Region(s) for which a Minimum Generation Emergency was declared, and then divide that result by the result in step (2).

(4) Multiply the total Minimum Generation Emergency Credit by the result in step (3). This result is the Market Participant's Minimum Generation Emergency Charge.

III.F.3.1.1. Allocation of Weekly Posturing Charges.

Real-Time NCPC Credits associated with the Posturing of facilities with weekly energy restrictions as determined pursuant to Section III.F.2.6.5 are allocated and charged to Market Participants in proportion to the sum of their Real-Time Load Obligations for the weekly energy restriction period, beginning with the first day in the weekly energy restriction period in which a Resource is postured through the last day of the period, or the day in which the actual restricted energy supply is exhausted, if earlier, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit.

This Section III.F.3.1.1 shall be effective through September 30, 2012.

III.F.3.2. Calculations

III.F.3.2.1 Day-Ahead NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total Day-Ahead NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead NCPC Credits, as previously calculated, for generating Resources, Postured generators (non-VAR) and Dispatchable Asset Related Demand (pumps only).

III.F.3.2.2 Local Second Contingency Protection Resource NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participants' Day-Ahead Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.3 VAR related NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total VAR related NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead VAR credits.

III.F.3.2.4 NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the NCPC Charges for the Day-Ahead Energy Market by allocating the total economic NCPC cost for the Day-Ahead Energy Market to each Market Participant based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub). For each External Node, if there are any Day-Ahead External Transaction purchase credits for each External Transaction purchase or Increment Offer cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Load Obligations at the External Node. If there are any Day-Ahead External Transaction sale credits for each External Transaction sale or Decrement Bid cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Generation Obligations at the External Node.

III.F.3.2.5 Local Second Contingency Protection Resource NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Day-Ahead Energy Market for each affected Reliability Region by allocating the total Local Second Contingency Protection Resource NCPC cost for the Day-Ahead Energy Market for each affected Reliability Region to each Market Participant within each affected Reliability Region based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations within the affected Reliability Region (not including the Hub).

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Day-Ahead Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.F.3.2.6 VAR Charges, Day-Ahead Energy Market, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the VAR Charges for the Day-Ahead Energy Market by allocating the sum of the total VAR related NCPC cost for the Day-Ahead Energy Market to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.7 Non-Synchronous Condenser related Economic NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total non-Synchronous Condenser related economic NCPC cost associated with the Real-Time Energy Market by summing all Market Participant's Real-Time NCPC Credits not related to Synchronous Condensers, as previously calculated, and the total Synchronous Condenser related NCPC cost (non-VAR related) associated with the Real-Time Energy Market by summing all Market Participants' non-VAR related Real-Time Synchronous Condenser related NCPC Credits for generating Resources, pool scheduled External Transaction purchases, pool- scheduled External Transaction sales and Dispatchable Asset Related Demand Resources (pumps only), cancelled Pool-Scheduled Resources excluding Resources Postured for reliability.

III.F.3.2.8 Local Second Contingency Protection Resource NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total Local Second Contingency Protection Resource NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.9 SCR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total SCR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time SCR NCPC Credits.

III.F.3.2.10 VAR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total VAR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time VAR credits including VAR credits associated with Synchronous Condensers and Postured generating Resources.

III.F.3.2.11 [Reserved.]

III.F.3.2.12 Real-Time Load Obligation Deviation.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1) by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub).

III.F.3.2.13 [Reserved.]

III.F.3.2.14 Real-Time Generation Obligation Deviation at External Nodes.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Generation Obligation Deviation at External Nodes by summing the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

III.F.3.2.15 Other.

The ISO calculates for each Operating Day the non-Postured non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related, non-Regulation and non-SCR related economic NCPC Charges for the Real-Time Energy Market for each Market Participant by allocating the total Real-Time non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related and non-SCR related NCPC cost to each Market Participant based on their daily pro-rata share of the daily sum of the following hourly Real-Time deviations:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resources Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or

(Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following ISO Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following ISO Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1)
[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.
[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

plus,
(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.2.16 Local Second Contingency Protection Resource NCPC Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Real-Time Energy Market for each Market Participant within each affected Reliability Region by allocating the total Real-Time Local Second Contingency Protection Resource NCPC cost to each Market Participant within each affected Reliability Region based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Real-Time Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External

Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(a) For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, for hours in which there is a Local Second Contingency Protection Resource NCPC cost (as calculated in Section III.F.3.2.8) and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of proportional shares of Real-Time Load Obligations as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The proportionate share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
			Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-37 Line) Hoosick- Bennington Line (K-6	Vermont, Vermont Vermont	Allocated proportionally to the Vermont, West Central Massachusetts and

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
			Massachusetts
	Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	 West Central Massachusetts West Central Massachusetts Connecticut	Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
1385 Cable External Node	Northport-Norwalk Harbor (1385 Line)	Connecticut	100% to Connecticut
Cross Sound Cable External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(b) For each month, the ISO performs an evaluation of total Real-Time Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph b, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only) above its Minimum Consumption Limit.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.3.2.17 VAR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the VAR Charges (including Synchronous Condensers) associated with the Real-Time Energy Market by allocating the total Real-Time VAR cost to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.18 SCR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the SCR Charges associated with the Real-Time Energy Market by charging the total Real-Time SCR cost to the appropriate entities based on Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

~~SECTION III~~

~~MARKET RULE 1~~

~~APPENDIX H~~

~~OPERATIONS DURING COLD WEATHER CONDITIONS~~

~~**APPENDIX H**~~

~~**Operations During Cold Weather Conditions**~~

~~**Table of Contents**~~

~~III.H.1 INTRODUCTION~~

~~III.H.2 DEFINITIONS AND INTERPRETATIONS~~

~~III.H.3 PROCEDURES~~

~~III.H.3.1 Natural Gas Industry Coordination~~

~~III.H.3.2 Reporting Anticipated Generating Resource Availability~~

~~III.H.3.3 Cold Weather Condition Evaluation~~

~~III.H.3.4 Cold Weather Condition Actions~~

~~III.H.3.5 [Reserved.]~~

~~III.H.3.6 [Reserved.]~~

~~III.H.3.7 [Reserved.]~~

~~Attachment 1 - [Reserved.]~~

~~III.H.1. INTRODUCTION~~

~~This Appendix H addresses system operations during Cold Weather Conditions. Appendix H includes provisions for coordination of the different scheduling timeframes between the gas and electric systems and the formal processes that need to exist among the ISO, owners of gas-fired generation and the natural gas industry during Cold Weather Conditions.~~

~~This **Appendix H** addresses ISO scheduling during Cold Weather Conditions that will allow natural gas units to receive their commitment status in sufficient time to purchase gas by the gas nomination deadline.~~

~~This **Appendix H** will provide electric scheduling certainty necessary to support Day-Ahead gas nominations by owners of natural gas units.~~

~~This **Appendix H** defines processes that will enable the ISO to forecast and operate with greater certainty and facilitate higher unit availability during Cold Weather Conditions.~~

~~This **Appendix H** includes definitions of key terms, responsibilities of Market Participants and the ISO, as well as rules for outage evaluation, outage requests and reporting.~~

~~III.H.2. DEFINITIONS AND INTERPRETATIONS~~

~~Whenever used in this Appendix H, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2.~~

~~For the purposes of this Appendix H, temperatures are the average of the temperatures obtained from the weather services for New England as described in the System Operating Procedure to Create Load Forecast, which is available on the ISO's website at http: www.isone.com/smd/system operating procedures.~~

~~III.H.3. PROCEDURES~~

~~III.H.3.1 [Reserved.]~~

~~III.H.3.2 Reporting Anticipated Generating Resource Availability~~

~~During a Cold Weather Watch, Cold Weather Warning or Cold Weather Event, Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the generating Resource's ability to procure fuel for the pertinent Operating Day and physical limitations that could reduce generating Resource output for the pertinent Operating Day.~~

~~III.H.3.3 Cold Weather Condition Evaluation~~

~~(a) Develop Seven-Day Forecast.~~ ~~Each day, the ISO develops a Seven-Day Forecast by 1100 in accordance with the current ISO New England System Rules. In addition to the requirements of the applicable ISO New England System Rules, the Seven-Day Forecast will include the following inputs:~~

- ~~A review of any notices issued by gas pipeline operators, communications with generating Resources, and an assessment of the potential unit availability impact of actions announced in those notices.~~
- ~~A review of forecasted weather conditions to determine if Cold Weather Conditions are forecast and an assessment of the potential impact of such weather conditions on natural gas unit availability.~~
- ~~A survey of dual fuel units normally operating on natural gas that have switched or are able to switch to their secondary fuel based on information received from each dual fuel generating Resource.~~

~~In the forecast process, the ISO will not change (based on the foregoing information) any data reflecting unit operating limits or unit availability unless requested by the Lead Market Participant for a generating Resource. However, the ISO may change such data reflecting unit operating limits or unit availability, in accordance with other Tariff provisions, ISO New England Operating Procedures or ISO New England Manuals, based upon information provided to the ISO by a Market Participant for a generating Resource.~~

~~(b) Evaluate Seven-Day Forecast~~~~. Each day during the Winter Capability Period, the ISO will evaluate the Seven-Day Forecast and perform a Cold Weather Conditions analysis for each day of the following seven-day period. By 1100 each day the ISO will post the Seven-Day Forecast and the applicable Cold Weather Condition for each day of the period.~~

~~The applicable Cold Weather Conditions are:~~

- ~~Cold Weather Watch~~
- ~~Cold Weather Warning~~
- ~~Cold Weather Event~~
- ~~No Cold Weather Condition applies~~

~~The Seven-Day Forecast will indicate, for each day, the anticipated reductions (MW) in total operable generating capacity resulting from the Cold Weather Conditions and the ISO may include the capacity (MW) of resources without a Capacity Supply Obligation (based on the historical offer trends) as operable generating capacity in the forecast. The ISO may update the Seven-Day Forecast and the Cold Weather Condition for each of day of the seven-day period at any time during the day. This process can result in declaration, reaffirmation or cancellation of the applicable Cold Weather Condition for any day in the forecast period subject to the limitations set forth in Section III.H.3.4(c)(i).~~

~~III.H.3.4 Cold Weather Condition Actions~~

~~(a) Cold Weather Watch~~

~~(i) Cold Weather Watch declarations:~~

- ~~Cold Weather Watch declarations will be made in advance for the following seven-day period as described in Section III.H.3.3.~~

- ~~If the ISO declares a Cold Weather Watch for specific days in the next seven-day period or revises an existing Cold Weather Condition to a Cold Weather Watch, a notice will be prominently posted on the ISO's website indicating the date(s) of a Cold Weather Watch.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Watch has been declared.~~

~~(b) Cold Weather Warning~~

~~(i) Cold Weather Warning declaration~~

- ~~Cold Weather Warning declarations will be made in advance for the following seven-day period as described in Section III.H.3.3.~~

- ~~If the ISO declares a Cold Weather Warning for specific days in the coming seven-day period or revises an existing Cold Weather Condition to a Cold Weather Warning, a notice will be prominently posted on the ISO's website indicating the date(s) of the Cold Weather Warning.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Warning has been declared.~~

~~(ii) Cold Weather Warning actions.~~

~~When a Cold Weather Warning is declared:~~

- ~~The ISO will request that all dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of Cold Weather Event days being declared.~~

- ~~The ISO will apply the procedures used in Master/Local Control Center Procedure #2 for the approval of transmission outage requests received for a day in the period for which a Cold Weather Warning has been forecast or declared.~~

~~(c) Cold Weather Event~~

~~(i) Cold Weather Event declaration~~

- ~~Cold Weather Event Declarations will normally be made no later than 1100 two days prior to the Operating Day unless circumstances require a later notice. Once a Cold Weather Event has been declared for a day of the up-coming seven-day period, it will not be cancelled.~~

- ~~If the ISO declares a Cold Weather Event for specific days, a notice will be prominently posted on the ISO's website indicating the date(s) of the Cold Weather Event, and all Supply Offers, Demand~~

~~Bids, Increment Offers, Decrement Bids and all External Transactions normally required to be submitted by 1200 on [date] shall be due by 0900 on [date] Seven Day Forecast is posted on the ISO website.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Event has been declared.~~

~~(ii) Cold Weather Event actions. When a Cold Weather Event is declared:~~

- ~~The ISO will communicate the Cold Weather Event to State Regulators, the Electric/Gas Operations Committee, members of the Markets, Reliability and Participants Committees, and Lead Market Participants, Designated Entities and Demand Designated Entities.~~

- ~~Public appeals and other actions of ISO New England Operating Procedure No. 4 will be implemented by the ISO as appropriate.~~

- ~~The ISO will communicate the potential for capacity shortage to other Control Areas and Reliability Coordinators, and will request their assistance if necessary.~~

- ~~The ISO will implement an alert under the provisions of Master/Local Control Center Procedure #2.~~

- ~~The ISO will request that Market Participants with dual-fueled units that normally burn natural gas to voluntarily switch to secondary fuel for Cold Weather Event Days. The ISO will communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to alternate fuel.~~

- ~~The ISO will change the Day-Ahead Energy Market trading deadline for Cold Weather Event days from 1200 to 0900 of the day prior to the Operating Day. Market Participants are responsible for submitting Supply Offers for the Day-Ahead Energy Market by the 0900 trading deadline. In connection with the submission of Supply Offers for each Cold Weather Event Operating Day, the Lead Market Participant of a generating Resource may re-declare the Resource's minimum run time and ramp rates to reflect limitations on the Resource's ability to receive gas off the pipeline due to gas pipeline operating limits but such re-declarations shall not exceed the period (generally the pertinent Gas Day) to which the gas pipeline operating limit applies.~~

- ~~Between 0900 and 1200 the Market User Interface (MUI) will be closed. The actions normally occurring at 1600 as described in Section III.1.10.8(b) of the Tariff and in ISO New England Manual M-11 will occur at 1200, including the posting of Day-Ahead Energy Market schedules and the opening of the Regulation market for offers.~~

- ~~After the submittal of Supply Offers and Demand Bids for the Day-Ahead Energy Market, the ISO will run the a Real-Time Resource Scheduling and Commitment (RT-RSC) Analysis, which will include the following inputs:~~

~~(i) The ISO load forecast~~

~~(ii) The Reserve Requirement established in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8~~

~~(iii) External Transactions forecast~~

~~(iv) Market Participant Supply Offers from generating Resources for the Day-Ahead Energy Market~~

~~(v) Assumptions with regard to the Real-Time operation of generating Resources that do not submit Supply Offers to the Day-Ahead Energy Market~~

~~(vi) Generation Requirement for Transmission (GRT) spreadsheet information~~

~~(vii) Must-Run Generation for VAR, Special Constraint Resources, and local transmission (emergency work)~~

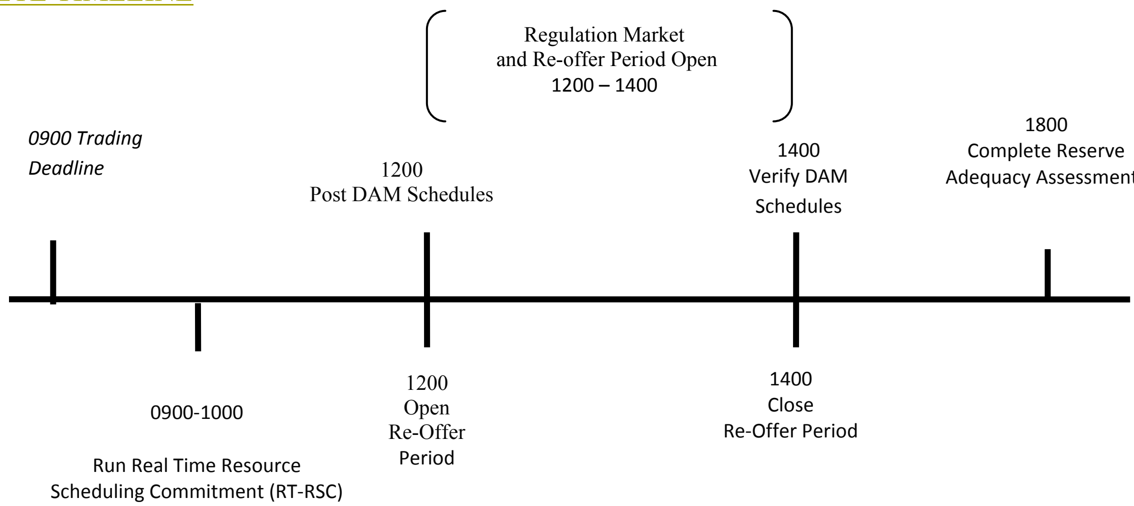
~~(viii) Available Dispatchable Asset Related Demand Resources~~

- ~~Between 0900 and 1000 the day prior to the Operating Day, Market Participants with gas-fired generating Resources that are determined by this evaluation to be necessary to meet load forecast and Reserve Requirements in accordance with Operating Procedure No. 8, will be advised~~

~~(simultaneously, to the extent feasible) that they will be pool-scheduled in the Day-Ahead Energy Market for a specified minimum set of hours and MW levels.~~

- ~~The Re-Offer Period described in Section III.1.10.9(a) of the Tariff and normally occurring between 1600 and 1800 will instead occur between 1200 and 1400. During the Re-Offer Period, a Market Participant with a generating Resource may re-declare the Resource's ramp rate to reflect limitations on its ability to take gas off the pipeline due to gas pipeline operating limits. Such re-declarations shall apply only to the gas days to which the gas pipeline operating limits apply. The above schedule is illustrated below. More detailed descriptions of the non-Cold Weather Event timeline may be found in ISO New England Manual M-11.~~

DELETE TIMELINE



- ~~Market Participants responsible for gas-fired generating Resources that are scheduled in the Day-Ahead Energy Market or that were advised by the ISO that their Resources will be committed for reliability purposes as determined by the RT-RSC shall provide to the ISO as soon as practicable but in no event later than the close of the Re-Offer Period evidence of and confirmation of gas volume nominations sufficient to deliver the energy scheduled for such Resource.~~

- ~~The information that is received by the ISO about gas-fired adequacy assessment process will be used in subsequent executions of the reserve adequacy assessment process.~~

- ~~As part of the reserve adequacy assessment process that takes place between 1400 and 1800, and as necessary throughout the Operating Day, the ISO will review the then-current gas nomination information as posted on the natural gas pipeline's Electronic Bulletin Board to better understand the overall New England gas supply situation. The ISO will, to the extent reasonably feasible, contact Market Participants responsible for generating Resources as needed to address concerns that result from the ISO's review of nomination information. This information will be used in performing the reserve adequacy assessments.~~

- ~~In the reserve adequacy assessment process, the ISO will change Operating Limits or Resource availability only in accordance with ISO Operating Documents or if such a change is requested by the Market Participant responsible for the generating Resource.~~

- ~~The ISO will provide through the 2200 forecast in accordance with III.13.1.4.4.1 an indication that Real-Time Demand Response Resources may be activated.~~

- ~~The ISO will dispatch Real-Time Emergency Generation Resources if and when the ISO reaches the applicable actions of ISO New England Operating Procedure No. 4.~~

~~III.H.3.5 [Reserved.]~~

~~III.H.3.6 [Reserved.]~~

~~III.H.3.7 [Reserved.]~~

~~**Attachment 1**~~

~~[Reserved]~~

Alternatives to Closing the DAM at 9:00 AM

Closing the DAM at 10:00 AM and the RAA at 5:00 PM.

- Move the DA Market bid deadline by two hours (10:00am), compress the DA clear to 3.5 hours (1:30 PM), compress the reoffer to half an hour (2:00 PM), and compress the 1st RAA to 3 hours (5:00 PM). That would allow the 1st RAA commitment to be issued by 5 pm.
- ISO has stated that closing the RAA at 4:00 PM versus 5:00 PM allows them to access less than 1000 additional MWs of long-lead units
- There are approximately 900 MWs of RTEG and RTDR available to the ISO.
- Liquidity in the gas market does not occur until after 9:00 AM.

ISO-NE Proposal

SECTION I – GENERAL TERMS AND CONDITIONS

I.2.2. Definitions:

Reference Level is defined in Section III.A.~~5.6.1~~7 of Appendix A of Market Rule 1.

Re-Offer Period is the period that normally occurs between the posting of the Day-Ahead Energy Market results and 1:00 p.m.~~16:00 and 18:00~~ 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.

SECTION III

MARKET RULE 1

STANDARD MARKET DESIGN

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

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

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

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

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

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

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 9:00 a.m.~~12:00 noon~~ on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the ~~re-offer period~~Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

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

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

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $0.0/MWh; and

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to $1,000/MWh.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may be revised to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its minimum run time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's minimum run time; and

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

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

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

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

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

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

III.1.10.7 External Transactions.

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

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

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) All Real-Time External Transactions shall be scheduled and curtailed in accordance with the ISO New England Manuals and all applicable tariffs.

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

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

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

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

(ii) FCA Cleared Export Transactions:

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

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

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

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

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

(iii) Same Reserve Zone Export Transactions:

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

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

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

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

(iv) Unconstrained Export Transactions:

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

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

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

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

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

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

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

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

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

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

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

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

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

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than ~~4:00~~12:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource ~~re-offer period~~Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 1:00 ~~4:00 p.m. to 6:00~~ p.m. on the day before each Operating Day or such other ~~re-offer period~~Re-Offer Period as necessary to account for software failures or other events. During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the ~~re-offer period~~Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than ~~60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to~~ 20 minutes prior to the hour~~, when the ISO has notified the Market Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period),~~ as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

(c) During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the ~~re-offer period~~Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the ~~re-offer period~~Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect.

(d) **[Reserved.]**

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output levels as practical, consistent with Accepted Electric Industry Practice.

(e) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource's notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with good utility practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources.

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 ~~noon~~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.

MARKET MONITORING,

REPORTING AND MARKET POWER MITIGATION

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources.

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, ~~and~~ 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. Market Participant requests to alter a Reference Level must be submitted to imm@iso-ne.com.

III.A.3.1. Consultation ~~Prior to Offer~~.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor no later than 90 minutes after the submission deadline for ~~at least one hour prior to the close of~~ the Day-Ahead Energy Market ~~offer deadline~~. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period ~~of the Real-Time Energy Market,~~ the Market Participant must contact the Internal Market Monitor no later than 30 minutes after ~~at least one hour prior to~~ the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by 5:00 p.m. the day prior to the Operating Day. 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. A Market Participant request pursuant to this section must be submitted to imm@iso-ne.com.

~~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.~~

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 least cost fuel type in the calculation of cost-based Reference Levels pursuant to Section III.A.7.5 below. If a Market Participant requests that the Internal Market Monitor use a higher cost fuel type in the calculation of the cost-based Reference Level, then it must provide the Internal Market Monitor written verification as to the cause for the use of the higher cost fuel and expected duration of such use. The verification as to cause must include a statement as to how the use of the higher cost fuel is consistent with ensuring the availability of the Resource.

In the event that:

(a) the lower cost fuel becomes physically unavailable after the offer deadline for the Operating Day;
(b) the offer for the Operating Day is at or below the Reference Level based on the higher cost fuel, and;
(c) the Market Participant notifies the Internal Market Monitor; then

the Internal Market Monitor shall evaluate the information provided by the Market Participant. If the Internal Market Monitor determines that the Reference Level should be based on the more expensive fuel, the Internal Market Monitor may apply a Reference Level based on the more expensive fuel, or treat the offer as not violating applicable conduct tests for the Operating Day for which the offer is submitted. At the time of notification, the Market Participant shall provide all available documentation showing why the Resource must use the higher-priced fuel, such as a fuel supplier notice of the interruption. Within five business days of the Operating Day, if not already made available to the Internal Market Monitor during the initial notification, the Market Participant shall provide full documentation regarding the use of the higher-priced fuel, including evidence that the higher priced fuel was used or, alternatively, of the lack of energy generated, as well as evidence of the fuel interruption.

If the Market Participant fails to provide supporting information within five business days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes. Market Participant requests and supporting information must be submitted to imm@iso-ne.com.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. The Reference Levels will be made available on a daily basis. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

NCPC ACCOUNTING

III.F.1. Overview.

Accounting for the provision of Operating Reserve and Replacement Reserve is performed on a daily basis. A generating Resource of a Market Participant that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Day-Ahead Energy Market subject to limitations when the Supply Offer includes Self-Scheduled hours as discussed in Section III.F.1.1.1. A generating Resource of a Market Participant, including a Local Second Contingency Protection Resource, that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Real-Time Energy Market provided that the Resource satisfies the criteria specified in Sections III.F.1.1.2 and III.F.2.1.7 below.
NCPC Credits are also provided for dispatchable External Transactions (both purchases and sales), for Increment Offers and Decrement Bids at External Nodes, for generating units operating as Synchronous Condensers at the direction of the ISO, for Dispatchable Asset Related Demand Resources (pumps only) that are not Self-Scheduled, for cancellation of generating Resources that are Pool-Scheduled Resources and for generating units backed down for the purposes of providing Operating Reserve or VAR support. NCPC calculations shall be performed separately for the Day-Ahead and Real-Time Energy Markets.

III.F.1.1. Effect of Self-Schedules on NCPC Credits

III.F.1.1.1 Ineligibility for NCPC Credits (Day-Ahead Energy Market).

In the Day-Ahead Energy Market, the Resource's Self-Scheduled hours shall be the Self-Scheduled hours submitted in the Supply Offer.

(a) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation, a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains two blocks of contiguous Self-Scheduled hours separated by less than the Resource's minimum down time. For purposes of this calculation, a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days, or crosses the boundary between two Operating Days as described in (a) above, and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of non Self-Scheduled hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

III.F.1.1.2 Ineligibility for NCPC Credits (Real-Time Energy Market).

In the Real-Time Energy Market, the Self-Scheduled hours for the purpose of determining NCPC Credit eligibility shall be the Self-Scheduled hours from the Day-Ahead Schedule as modified in the Re-Offer ~~electronic bidding~~Period ~~as described in Market Rule I Section III.1.10.9(a)~~ ~~(the Real-Time schedule as of 18:00 hours of the day prior to the Operating Day)~~, including any redeclaration of Self-Scheduled hours by a Market Participant pursuant to Section 8 of ISO New England Manual-11.

(a) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if its Supply Offer (submitted either in the Day-Ahead Energy Market or during the Re-Offer Period) contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if it submits (as a Supply Offer in the Day-Ahead Energy Market or during the Re-Offer Period) two Self-Schedules separated by less than the Resource's minimum down time. For purposes of this calculation a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first Operating Day as meeting the minimum down time requirement but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days or crosses the boundary between two Operating Days and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

(e) For purposes of the above determinations, the minimum run time portion of a Real-Time Commitment Period commences with the first hour of the Real-Time Commitment Period in which the actual metered output of the generating Resource equals or exceeds 75 percent of the generating Resource's Economic Minimum Limit; provided that, if the Resource is a Fast Start Generator that never reaches 75 percent of its Economic Minimum Limit during its Real-Time Commitment Period, its minimum run time will commence with the first hour in which it has positive output. Each Real-Time Commitment Period is evaluated separately for the purpose of determining NCPC Credit eligibility.

The Real-Time NCPC Credit eligibility criteria set forth in subsections (a) through (e), above, shall be waived for additional hours of operation that result from an ISO request for extension of the Resource's operating schedule.

III.F.2. NCPC Credits.

NCPC Credits are calculated for each of the following situations:

(1) Pool-Scheduled Resources (Generators), including Local Second Contingency Protection Resources (Generators) and External Transactions (Day-Ahead and Real-Time Energy Markets); Increment Offers and Decrement Bids cleared at External Nodes.

(2) Pool-Scheduled Resources (Synchronous Condensers and Special Constraint Resources ("SCR") - Real-Time Energy Market)

(3) Canceled Pool-Scheduled Resources (Real-Time Energy Market)

(4) Resources postured for reliability purposes (Real-Time Energy Market)

(5) Dispatchable Asset Related Demand Resources (pumps only) that are postured for reliability purposes in Real-Time.

(6) Self-Scheduled generating Resources providing Operating Reserves by operating in accordance with Dispatch Instructions in non-Self-Scheduled hours or at levels above the Self-Scheduled MW in Self-Scheduled hours during an Operating Day in which they have offered a contiguous block of Self-Scheduled hours, which meet the criteria for such Self-Schedules set forth in Section III.F.1, at least equal to their minimum run times.

III.F.2.1. Credits for Generating Resources.

For each Operating Day, the ISO calculates the NCPC Credit due each Market Participant for generating Resources.

In the Day-Ahead Energy Market, eligible generating Resources shall receive Day-Ahead NCPC Credits for all hours that are not Self-Scheduled. Except as otherwise provided in this Appendix F, all eligible generating Resources are eligible except generating Resources that have Self-Scheduled hours that do not meet the criteria set forth in Section III.F.1.1.1 are ineligible for Day-Ahead NCPC Credit. For purposes of the Day-Ahead NCPC Credit calculations, the Self-Scheduled hours shall be the Self-Scheduled hours in the Participant's Supply Offer.

In the Real-Time Energy Market, an eligible generating Resource is eligible to receive Real-Time NCPC Credits for all hours that are not Self-Scheduled and for MW amounts in excess of the Self-Scheduled MW for Self-Scheduled hours when the Resource operates above the Self-Scheduled MWs at the ISO's request. A generating Resource is not eligible to receive Real-Time NCPC Credits for any hour in which the Resource is ramping up from an off-line state prior to being released for dispatch, or ramping down after receiving a shutdown order. Self-Scheduled hours include hours when the Resource is ramping up to a Self-Scheduled hour from an off-line state, or down from a Self-Scheduled hour to an offline state and hours when the Resource is Self-Scheduled for Regulation. Eligible generating Resources shall consist of Pool-Scheduled Resources and Self-Scheduled Resources that meet the criteria in Section III.F.1.1.2 and any generating Resources specifically made eligible for Real-Time NCPC Credits in other Sections of this Market Rule 1.

III.F.2.1.1 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

III.F.2.1.2 Hourly Day-Ahead Offer Amount.

The ISO calculates the generating Resource's hourly Day-Ahead offer amount based on its Day-Ahead Offer Data that was utilized by the ISO in making the initial commitment decision and the generating Resource's cleared Day-Ahead MWh for that hour.

For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

(a) The ISO accounting process applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Resource Offer Data and if the Start-Up Fee is applicable for the MWh and status of the Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource Day-Ahead and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant. The Start-Up Fee will be associated with the first hour of the Resource's minimum run time on the day for which the Resource is committed. The Start-Up Fee will always be on the same Operating Day for both the Day-Ahead and Real-Time Energy Markets for purposes of calculating Real-Time NCPC Charges/Credits.

(b) Day-Ahead NCPC Credit calculations reflect the Start-Up Fee for the appropriate hot, intermediate, or cold state of the generating unit as it was scheduled in the Day-Ahead Energy Market.

III.F.2.1.3 Hourly Day-Ahead Value.

The ISO *calculates* the generating Resource's hourly Day-Ahead value as: generating Resource cleared Day-Ahead MWh * Day-Ahead LMP

III.F.2.1.4 Daily Day-Ahead Credit.

The ISO calculates the daily Day-Ahead credit for each generating Resource as follows:

(a) Sum hourly Day-Ahead offer amounts, including applicable No-Load Fees and Start-Up Fees, for the day.

(b) Sum hourly Day-Ahead values for the day.

(c) Day-Ahead credit equals any portion of the generating Resource's total Day-Ahead offer amount in excess of its total Day-Ahead value.

III.F.2.1.5 Day-Ahead Credit Allocation.

The ISO allocates the Day-Ahead credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource was scheduled and was eligible for NCPC Credit pro-rata based on Day-Ahead Load Obligations as follows:

Hourly Credit = Daily Credit * (Day-Ahead Load Obligations in scheduled hour) / (Total Day-Ahead Load Obligations in all scheduled hours))

[Note: Each credit is allocated back retaining its flag (Local Second Contingency Protection Resource, VAR etc.)]

III.F.2.1.6 Day-Ahead NCPC Credit: Hourly Market Participant Credit; Operating Day Total.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credit and the total Day-Ahead NCPC Credit for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset.

(b) For each scheduled hour, if the generating Resource is flagged specifically for the provision of VAR or voltage support, the Market Participant's share of Day-Ahead VAR credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits for all generating Resources for that Operating Day.

(c) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead VAR credits is equal to

50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits and all Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day.

(d) For each scheduled hour, if the generating Resource is not flagged as a Local Contingency Protection Resource or VAR, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.7 Real-Time NCPC Credit Eligibility.

The ISO determines eligibility for Real-Time NCPC Credits. The following operating guidelines are used in the determination of Real-Time NCPC Credit eligibility:

(a) Generating Resources must be following Dispatch Instructions. For any hour that the generating Resource is not following Dispatch Instructions and the difference between the generating Resource's energy value, in dollars, and energy offer amount, in dollars, (in this case, energy offer amount includes No-Load Fee and incremental energy price and does not include any Start-Up Fee) in that hour is negative, the generating Resource's energy offer amount, in dollars, and energy value, in dollars, in that hour is excluded from the Real-Time NCPC Credit calculations.

(b) Generating Resources that trip during their Real-Time Commitment Periods are treated as set forth below:

(i) If the generating Resource trips during its minimum run time period and the generating Resource is otherwise eligible to receive Real-Time NCPC Credit, the Resource will be eligible for Real-Time NCPC Credit for the period beginning with the start of the Real-Time Commitment Period and ending at the time of the trip. For purposes of determining such generating Resource's eligibility for Real-Time NCPC Credit, such generating Resource shall be eligible to recover a portion of its Start-Up Fee equal to the applicable Start-Up Fee multiplied by the quotient (not to exceed 1) of the generating Resource's hours of operation during the current Real-Time Commitment Period and the generating Resource's minimum run time (Start-Up Fee* (Hours of operation/minimum run time)).

(ii) If the generating Resource trips after its minimum run time has been satisfied and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource will be eligible to receive Real-Time NCPC Credit for hours that were not Self-Scheduled during that Real-Time Commitment Period.

(iii) If the generating Resource trips, is requested to restart by the ISO, and returns to operate as requested, and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource is eligible to receive Real-Time NCPC Credits (including Start-Up Fee, No-Load Fee and incremental Energy price) for the new Real-Time Commitment Period.

(iv) Generating Resources that trip and return to operate that are not requested to restart by the ISO are treated as Self-Scheduled Resources and are not eligible for Real-Time NCPC Credits (Start-Up Fees and No Load Fee) for the new Real-Time Commitment Period.

When a generating Resource trips off line as the result of an equipment failure that involves equipment located on the electric network beyond the low voltage terminals of the generating unit step-up transformer, the ISO shall not treat the event as a trip for the purposes of determining the generating Resource's eligibility for Real-Time NCPC Credit for that Real-Time Commitment Period. It is the responsibility of the Lead Market Participant for the generating Resource to inform the ISO at xtrip@iso-ne.com within thirty (30) days that the trip was the result of such a transmission-related event.

(c) If a generating Pool-Scheduled Resource is otherwise eligible to receive Real-Time NCPC Credit and waives its minimum run time at the ISO's request, or if the ISO accepts an offer from a generating Pool-Scheduled Resource that is otherwise eligible to receive Real-Time NCPC Credit to waive its minimum run time and the ISO agrees to allow the Resource to shut down prior to completion of the generating Pool-Scheduled Resource's minimum run time:

(i) The generating Pool-Scheduled Resource shall be considered to have completed its minimum run time in calculating Real-Time NCPC Credits for which the generating Pool-Scheduled Resource is otherwise eligible; and

(ii) The generating Pool-Scheduled Resource's applicable Start-Up Fee shall be included in the calculation of said NCPC Credits.

III.F.2.1.8 Hourly Real-Time MWh.

The ISO determines the generating Resource's hourly Real-Time MWh based on the values submitted to the ISO by the Assigned Meter Reader for that hour.

III.F.2.1.9 Hourly Real-Time Energy Offer Amount.

The ISO calculates the generating Resource's hourly Real-Time energy offer amount based on its prices contained in the Supply Offer (if said Supply Offer has been mitigated, the mitigated Supply Offer shall be used for this calculation) for all eligible hours. For pool-scheduled hours, the Supply Offer price is multiplied by the lesser of the generating Resource's Desired Dispatch Point (provided that any Desired Dispatch Point below the Resource's Economic Minimum Limit will be deemed equal to the Economic Minimum Limit) or its actual metered output for that hour less the Resource's cleared Day-Ahead MWh. For generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours, the Supply Offer price (excluding the Start-Up Fees and No-Load Fee) is multiplied by the lesser of the DDP or actual metered quantity less the greater of the Resource's Self-Scheduled MW or the Resource's cleared Day-Ahead MWh. Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the output of the unit that is attributable to its submittal of a Self-Schedule for Regulation. For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

III.F.2.1.10 Application of Start-Up Fee and Hourly No-Load Fee.

The ISO applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Generator Offer Data and if the Start-Up Fee is applicable for the MWh and status of the generating Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource in Real-Time and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant or if that Participant's Resource was scheduled in the Day-Ahead Energy Market. The No-Load Fee is not applicable in any hour if the total number of hours that the Resource cleared in the Day-Ahead Energy Market is greater than the total number of hours that the Resource had actual generation greater than zero.

If the total number of hours that the Resource had actual generation greater than zero is greater than the total number of hours that the Resource cleared in the Day-Ahead Energy Market, the No-Load Fees would be applicable once the total number of hours that the Resource actually ran in Real-Time exceeded the total number of hours that the Resource cleared in the Day-Ahead Energy Market.

III.F.2.1.11

If applicable, when a generating Resource is started during the day at the direction of the ISO, the generating Resource's Real-Time offer amount calculated for that day includes its Start-Up Fee based on the appropriate hot, intermediate, or cold state of the generating Resource. For generating Resources that start generating for the ISO from a condensing state, the applicable Start-Up Fee for that generating Resource shall be the Start-Up Fee submitted that is associated with the hot state of the unit.

III.F.2.1.12

If applicable, the generating Resource's Real-Time calculated offer amount includes its hourly No-Load Fee prorated for all hours of operation as follows, using a 10% tolerance:

> If: lesser of (Real-Time MWh or Desired MW) < .9 * (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time),
> Then: hourly No-Load Fee is prorated by (lesser of (Real-Time MWh or Desired MW) / (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time).

III.F.2.1.13 Generating Resource Hourly Real-Time Value.

The ISO calculates the generating Resource's hourly Real-Time value for all eligible hours as:

> ((generating Resource metered value – max (generating Resource cleared Day-Ahead MWh, generating Resource Real-Time Self-Schedule MWh)) * (Real-Time LMP at generating Resource Node)) + generating Resource Regulation Opportunity Cost.

III.F.2.1.14 Generating Resource Daily Real-Time Credits.

The ISO calculates the daily Real-Time credits for each generating Resource as follows:

(a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day.

(b) Sum hourly Real-Time values for the day.

(c) Real-Time credits are equal to any portion of the generating Resource's total Real-Time offer amount in excess of its total Real-Time value.

III.F.2.1.15 Real-Time Credit Allocation.
The ISO allocates the Real-Time credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource actually operated and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * (Real-Time Load Obligation in operating hour) / Total Real-Time Load Obligations in all operating hours)

III.F.2.1.16 Real-Time NCPC Credits; Hourly Market Participant Credit; Operating Day Total.
The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as providing Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time SCR NCPC Credits for all generating Resources for that Operating Day,

(b) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(c) For each scheduled hour, if the generating Resource is flagged as a VAR Generator, the Market Participant's share of Real-Time VAR credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits for all generating Resources for that Operating Day,

(d) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time VAR credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits and all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(e) For each scheduled hour, if the generating Resource is not flagged as a Local Second Contingency Protection Resource or VAR, the Market Participant's share of Real-Time economic NCPC Credit is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.17 Addition of Hourly Shortfall Payments.

Generating Resources that are Pool-Scheduled Resources in the Day-Ahead Energy Market that are available, can deliver Energy and are not Postured, but are not economically dispatched in Real-Time and have not changed their incremental energy offers during the ~~re-offer period~~Re-Offer Period, are eligible to receive the difference between the Real-Time and Day-Ahead LMP at the generator bus times the Day-Ahead scheduled MWh for hours when the Real-Time LMP is greater than the Day-Ahead LMP. Any payments made for each hourly shortfall are added to the total Real-Time economic NCPC Credits, Real-Time Local Second Contingency Protection Resource NCPC Credits or Real-Time VAR credits, as applicable, for the applicable Operating Day.

III.F.2.1.18 Addition of Minimum Generation Emergency Credits.

When a Minimum Generation Emergency has been declared (see Section 2.5.13.2 of ISO New England Manual M-11), generating Resources that are otherwise eligible to receive Real-Time NCPC Credits may be eligible to receive Minimum Generation Emergency Credits as provided below:

(a) Minimum Generation Emergency Credits will only be available in the Data Reconciliation Resettlement of the monthly services customer bill for the Operating Day(s) in which the Minimum Generation Emergency was declared.

(b) Minimum Generation Emergency Credits must be requested by sending a letter to the ISO's Market Support Services Department (custserv@iso-ne.com) within 20 business days after issuance of the monthly services customer bill that covers the hours of Minimum Generation Emergency for which a claim is being made. Requests received later than 20 business days after the issuance of the monthly services customer bill that includes the Minimum Generation Emergency hours for which a claim is being made will not be accepted.

(c) The lesser of the generating Resource's Desired Dispatch Point or actual metered output must be above the generating Resource's Economic Minimum Limit for each hour for which Minimum Generation Emergency Credit is requested.

(d) The Minimum Generation Emergency Credit for each eligible hour will be calculated as follows:

(i) The generating Resource's Economic Minimum Limit will be subtracted from the lesser of the generating Resource's Desired Dispatch Point ("DDP") or Real-Time Generation Obligation. Generating Resources with DDPs above Economic Minimum Limits because they are ramp rate constrained when being dispatched down to their Emergency Minimum Limits will have the result of the above calculation set to zero.

(ii) The result of step (i) will be multiplied by the Supply Offer price (in this case excluding the daily Start-Up Fee but not the hourly No-Load Fee) associated with the appropriate Supply Offer Energy block

(iii) The result of step (ii) will be reduced by any revenue received during that hour in the Real-Time Energy Market due to a non-zero LMP for the hour(s) for which the Minimum Generation Emergency was declared.

(e) Resources receiving Minimum Generation Emergency Credits under this Section III.F.2.1.18 shall be ineligible to receive Real-Time NCPC Credit for the same hour(s).
Charges associated with Minimum Generation Emergency Credits are discussed in Section 3 of this Appendix F.

III.F.2.2. Real-Time Credits for Pool-Scheduled Synchronous Condensers.

For each Operating Day, the ISO calculates the NCPC Credits due each Market Participant for Pool-Scheduled Resources scheduled as Synchronous Condensers.

III.F.2.2.1 Information Retrieved.

The ISO retrieves the following information:

(a) Dispatcher generation scheduling and operations logs

(b) Generator Offer Data

III.F.2.2.2 Duration of Pool-scheduled Periods of Synchronous Condensing Operations.

The ISO calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.

III.F.2.2.3 Condensing Offer Amount.

The ISO calculates each generating Resource's condensing offer amount for each period by multiplying the duration (in hours) by the hourly price to condense as specified in the Offer Data. If no hourly price to condense is listed in the Generator Offer Data, an hourly price of zero will be assumed and no payment will be made.

III.F.2.2.4 Condensing Credit.

When a generating Resource is requested to start condensing from an off-line state, a condensing credit is provided equal to the Resource's condensing Start-Up Fee as specified in the Offer Data.

III.F.2.2.5 VAR Credit.

If a unit is flagged as a VAR Resource and as a Synchronous Condenser, it will be compensated by a VAR credit.

III.F.2.2.6 Market Participant's Real-Time NCPC Condensing Credits.

The ISO calculates the daily Real-Time NCPC condensing credits for each Market Participant by summing all remaining hourly condensing generating Resource offer amounts, including applicable Start-Up Fees, for the Operating Day taking the Market Participant's Ownership Share into account.

III.F.2.2.7 Total Real-Time NCPC Condensing Credits.

The ISO sums the Real-Time NCPC condensing credits for all Market Participants for each Operating Day.

III.F.2.3. Credits for Pool-Scheduled External Transaction Purchases or Increment Offers at External Nodes.

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction purchases (modeled as Supply Offers at External Nodes) or Increment Offers at External Nodes as follows. These calculations only apply to External Transaction purchases submitted that are dispatchable and are submitted as source equals sink, or cleared Increment Offers at External Nodes.

III.F.2.3.1

Real-Time NCPC eligibility for pool-scheduled External Transactions Purchases (priced imports).

(a) For each hour that a pool-scheduled External Transaction purchase is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions purchases are only eligible for Real-Time NCPC Credits to the extent that the Real-Time transaction (measured in MWh) exceeds the associated Day-Ahead schedule.

III.F.2.3.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction purchases, and Increment Offers at External Nodes

(c) hourly pool-scheduled Day-Ahead and Real-Time External Transaction purchase offer price curve ($/MWh, MW), and hourly Increment Offer price curve ($/MWh,MW) submitted at External Nodes

(d) Day-Ahead and Real-Time LMPs

(e) Transaction flags (Local Second Contingency Protection Resource)

III.F.2.3.3 Day-Ahead Offer Amount.

The ISO calculates the hourly Day-Ahead offer amount for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the transaction offer price.

III.F.2.3.4 Hourly Day-Ahead Value.

The ISO calculates the hourly Day-Ahead value for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the Day-Ahead LMP at the applicable External Node.

III.F.2.3.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction purchase or Increment Offer at an External Node as follows:

(a) Day-Ahead offer amounts for the hour

(b) Day-Ahead values for the hour

(c) Day-Ahead NCPC Credits for External Transaction purchases or Increment Offers equal any portion of the import transaction's hourly Day-Ahead offer amount in excess of its hourly Day-Ahead value; provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction purchases or Increment Offers for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction sales or Decrement Bids for the External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the total External Transaction purchases or Increment Offers at the External Node are not offset by those of the total cleared External Transaction sales or Decrement Bids. The External Transaction purchases megawatts will be offset in order from highest to lowest price.

III.F.2.3.6 [Reserved.]

III.F.2.3.7 Day-Ahead NCPC Credits: Market Participant's Hourly Credits.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credits as follows:

For each scheduled hour, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour.

III.F.2.3.8 Hourly Real-Time Offer Amount.

The ISO calculates the hourly Real-Time offer amount for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead schedule by the transaction offer price.

III.F.2.3.9 Hourly Real-Time Value.

The ISO calculates the hourly Real-Time value for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead transaction MWh amount by the Real-Time LMP of the applicable External Node.

III.F.2.3.10 Real-Time Credits Calculation.

The ISO calculates the daily Real-Time credits for Real-Time External Transaction purchases as follows:

(a) Sum hourly Real-Time offer amounts for the day

(b) Sum hourly Real-Time values for the day

(c) Real-Time daily credit equals the portion of the External Transaction purchase's total daily Real-Time offer amount in excess of its daily Real-Time value.

III.F.2.3.11 Real-Time Credits Allocation.

The ISO allocates the Real-Time credits, for each External Transaction purchase for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.3.12 Real-Time NCPC Credits: Market Participant's Hourly and Operating Day Total. The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the External Transaction purchase is flagged as Local Second Contingency Protection Resource, the Market Participant's share of Local Second Contingency Protection Resource economic NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all External Transaction purchases for that Operating Day,

(b) For each scheduled hour, if the External Transaction purchase is not flagged as Local Second Contingency Protection Resource, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time NCPC Credits for all External Transaction purchases for that Operating Day.

III.F.2.4. Credits for Pool-Scheduled External Transactions Sales or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (Pumps Only).

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction sales (modeled as Demand Bids at External Nodes) or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (pumps only) as follows. Credits for pool-scheduled External Transaction sales or Decrement Bids at External Nodes only apply to External Transaction sales submitted that are Dispatchable and are submitted as source equals sink, or cleared Decrement Bids at External Nodes. Dispatchable Asset Related Demand Resources (pumps only) are eligible for NCPC Credits in hours for which they are not Self-Scheduled and are following Dispatch Instructions. Dispatchable Asset Related Demand Resources (pumps only) that are Self-Scheduled for any portion of an hour shall be considered Self-Scheduled for the entire hour and shall not be eligible for NCPC Credits in that hour.

III.F.2.4.1

Real-Time NCPC Credit eligibility for pool-scheduled External Transactions Sales (priced exports) is determined as follows:

(a) For each hour that a pool-scheduled External Transaction sale is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions sales are only eligible for Real-Time NCPC to the extent that the Real-Time transaction (measured in MWh) is scheduled to consume more than the associated Day-Ahead schedule.

III.F.2.4.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction sales (positive values), and Decrement Bids at External Nodes

(c) Pool-scheduled Day-Ahead scheduled consumption and Real-Time actual consumption for Dispatchable Asset Related Demand Resources (pumps only) (positive values)

(d) hourly pool-scheduled Day-Ahead and Real-Time External Transaction Demand Bid cost curve ($/MWh, MW), and hourly Decrement Bid cost curve ($/MWh,MW) submitted at External Nodes

(e) hourly pool-scheduled Real-Time Demand Bid cost curve ($/MWh, MW) for Dispatchable Asset Related Demand Resources (pumps only)

(f) Day-Ahead and Real-Time LMPs

III.F.2.4.3 Day-Ahead Bid Amount.

The ISO calculates the hourly Day-Ahead bid amount for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Demand Bid price.

III.F.2.4.4 Day-Ahead Cost.

The ISO calculates the hourly Day-Ahead cost for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Day-Ahead LMP at the applicable External Node.

III.F.2.4.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction sale or Decrement Bid at an External Node as follows:

(a) Day-Ahead bid amounts for the hour

(b) Day-Ahead costs for the hour

(c) Day-Ahead NCPC Credits for External Transaction sales or Decrement Bids equal any portion of the sale transaction's hourly Day-Ahead cost in excess of its hourly Day-Ahead bid amount provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction sales or Decrement Bids for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction purchases or Increment Offers for the same External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the External Transaction sales or Decrement Bids at the External Node are not offset by those of the total cleared External Transaction purchases or Increment Offers. The External Transaction sales megawatts will be offset in order from lowest to highest price.

III.F.2.4.6 [Reserved.]

III.F.2.4.7 Real-Time Bid Amount - External Transaction Sale.

The ISO calculates the hourly Real-Time bid amount for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the transaction Demand Bid price.

III.F.2.4.8 Real-Time Bid Amount - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time bid amount for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption less any cleared Day-Ahead consumption by the Dispatchable Asset Related Demand Resources (pumps only) Demand Bid price.

III.F.2.4.9 Real-Time Cost - External Transaction Sale.

The ISO calculates the hourly Real-Time cost for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the Real-Time LMP of the applicable External Node.

III.F.2.4.10 Real-Time Cost - Dispatchable Asset Related Demand Resources (Pumps Only).
The ISO calculates the hourly Real-Time cost for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption hourly deviations from the cleared Day-Ahead amount by the Real-Time LMP of the applicable Node.

III.F.2.4.11 Real-Time Credits - External Transaction Sale.
The ISO calculates the daily Real-Time NCPC Credits for Real-Time External Transaction sales as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals the portion of the External Transaction sale's total daily Real-Time bid amount that is less than its daily Real-Time cost.

III.F.2.4.12 Real-Time Credits Allocation - External Transaction Sale.

The ISO allocates the Real-Time NCPC Credits, for each External Transaction sale for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.4.13 Real-Time Credits -Dispatchable Asset Related Demand Resources (Pumps Only).
The ISO calculates the daily Real-Time NCPC Credits for Real-Time Dispatchable Asset Related Demand Resources (pumps only) as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals any portion of total daily Real-Time costs in excess of its total daily Real-Time bid amount of the Dispatchable Asset Related Demand Resource (pumps only).

III.F.2.4.14 Real-Time Credits Allocation -Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO allocates the Real-Time NCPC Credits, for each Dispatchable Asset Related Demand Resources (pumps only) for each Operating Day, back to each hour in the Operating Day in which the Dispatchable Asset Related Demand Resources (pumps only) was scheduled as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.5. Credits for Canceled Pool-Scheduled Resources (Generators).

For each Operating Day, the ISO calculates an NCPC Credit for the cancellation of a start-up prior to the assigned commitment time for any generating Pool-Scheduled Resource that:

(a) Was not scheduled by the ISO in the Day-Ahead Energy Market, and

(b) Was issued Dispatch Instructions to start-up in Real-Time. This cancellation credit is based on values submitted by Market Participants as part of the Resource's Offer Data. The following Offer Data parameters are utilized in the calculation: hot to cold time, hot to inter time, hot startup cost, inter startup cost, cold startup cost, hot notification time, inter notification time, and cold notification time.

III.F.2.5.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of canceled generating Resources (dispatcher log)

(b) Applicable generator Start-Up Fee (hot startup cost, inter startup cost or cold startup cost)

(c) Generator flags (Local Second Contingency Protection Resource, VAR, or SCR)

(d) generation data

III.F.2.5.2 Cancelled Start Credit Calculation.

The ISO credits each Market Participant for cancellation based on a pro-rata share of the applicable generating Resource's Start-Up Fee, and associated notification time parameter (hot, inter, or cold) utilized by the ISO in the original commitment decision. The credit for cancelled starts is calculated as follows:

Cancelled Start Credit = Applicable Generator Start-Up Fee * (1- ((Cancel Time) /(Notification Time))),

Where,

Applicable Generator Start-Up Fee	equals (i) Hot Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is less than the Hot to Inter Time; (ii) Inter Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Inter Time and less than the Hot to Cold Time; or (iii) Cold Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Cold Time,
Cancel Time	equals the difference, in hours, between the original ISO Commitment Order Time for the unit and the time at which the ISO cancelled the commitment of the unit. Cancel Time must be less than or equal to Notification Time, otherwise, the Cancelled Start Credit is set equal to zero,
ISO Commitment Order Time	equals the time at which the unit was originally requested to be synchronized to the New England Transmission system,
Notification Time	equals the applicable number of hours required to synchronize the unit to the system as submitted as part of the Generating Resource's Offer Data (Hot Notification Time, Intern Notification Time, or Cold Notification Time), and

Cancelled Start Credit is limited to be no greater than the applicable Start-Up Fee and notification time cannot be longer than 24 hours.

III.F.2.5.3 Real-Time NCPC Credit.

The Real-Time NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in Section III.F.2.5.2 above for all generating Pool-Scheduled Resources that were not originally flagged as a Local Second Contingency Protection Resource or VAR.

III.F.2.5.4 Local Second Contingency Protection Resource NCPC Credit.

The Real-Time Local Second Contingency Protection Resource NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.1.13 above for all generating Pool-Scheduled Resources that were originally flagged as Local Second Contingency Protection Resources.

III.F.2.5.5 VAR Credit.

The Real-Time VAR credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.5.2 above for all generating Pool-Scheduled Resources that were originally flagged as VAR.

III.F.2.5.6 Reserved.

III.F.2.5.7 SCR Credits.

The Real-Time SCR credits associated with generating units identified as SCR Resources are billed as provided for in Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.F.2.5.8 Example.

An example of the cancelled start calculation is as follows:

> Asset ID ABC was scheduled after the close of the Day-Ahead Energy Market to start at 6:00 am. ISO Cancelled the unit Start Time, in Real-Time, at 4:00 am. Cancel Time Column is calculated by subtracting Start time – Cancel time (6 – 4 = Cancel Time is 2)
> To determine the amount Cancelled Start we look at the Start-Up Fee and we multiply it by 1 minus Cancel Time divided by Time to Start.

III.F.2.6. Credits for Generating Resources and Dispatchable Asset Related Demand Resources (pumps only) Postured for Reliability.

The ISO credits Dispatchable Asset Related Demand Resources (pumps only) for responding to the ISO's request to increase consumption to a level above what would have been consumed during normal economic operation. The ISO credits Postured generating Resources, both pool-scheduled and Self-Scheduled, for responding to the ISO's request to reduce or suspend normal economic operation. A Resource shall be considered postured when it meets the conditions described in the definition of "Postured" in the Tariff. The ISO takes into account any generator Regulation credits associated with the postured generating Resource for the provision of Regulation while postured in calculating the posturing credits for generating Resources. For a Dispatchable Asset Related Demand Resource (pumps only) that is Postured, the posturing credits are calculated in accordance with Section III.F.2.4.

III.F.2.6.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)

(b) Generator Offer Data

(c) 5 minute generation data from EMS

(d) Real-Time LMP data

(e) Real-Time Generation Obligation

(f) Generator Regulation credits

III.F.2.6.2 Posturing Credit Calculation.

The ISO credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Daily Energy Restrictions.* For generating Resources without energy restrictions, the posturing credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – GRC

Where

PAG	equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;
AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
UB	equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
GRC	(Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Daily Energy Restrictions.* For generating Resources with energy restrictions, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the hour that posturing began and ending at the end of the calendar day,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP - UB) – GRC

Where:

PAG	equals the estimated hourly generation had the generating Resource not responded to Dispatch orders to reduce or suspend operation. Estimated operation for generating Resources following the Day-Ahead schedule prior to the posturing event will be determined by the Day-Ahead schedule. From the start of the posturing event through the end of the calendar day, PAG is set to the Day-Ahead schedule for as long as available energy would have supported the operation. For generating Resources responding to DDP’s in Real-Time or operating under Real-Time Self-Schedule changes prior to the posturing event, PAG will be set assuming economic operation would have occurred during posturing and throughout the day for as long as the available energy would have supported the operation;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource;

UB equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4 of the ISO New England Manual for Market Rule 1 Accounting, M-28.

(c) *Generating Resources With Weekly Energy Restrictions*. For generating Resources with weekly energy restrictions, credits are determined based on an estimate of the net opportunity cost in the energy market for the week. The net amount of a posturing credit shall not be negative.

Posturing credits for Resources with weekly energy restrictions are calculated as follows:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the first hour in the period in which a Resource is postured through the end of the weekly energy restriction period,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP-UB) – GRC

Where:

For an hour during which the Resource was postured, PAG equals the estimated hourly generation had the generating Resource not responded to Dispatch Instructions to reduce or suspend operation. For an hour in which the Resource was not postured, PAG equals the actual generation of the Resource. Once the total energy available for use during the weekly energy restriction period has between fully consumed by the estimated economic dispatch while postured plus actual generation while not postured, PAG equals zero; AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource;

UB equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4.2 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP – UB shall not be negative.

For postured resource with weekly energy restrictions, the credits and charges will be calculated for the weekly energy restriction period.

This subsection (c) shall be effective through September 30, 2012.

III.F.2.6.3 Real Time NCPC Credits.

The Real-Time NCPC Credits for posturing for the Operating Day are equal to the sum of the non-VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.4 Real Time VAR Credits.

The Real-Time VAR credits for posturing for the Operating Day are equal to the sum of the VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.5 Real Time NCPC Credits – Weekly Posturing.

The Real-Time NCPC Credits for Posturing for a Resource with weekly energy restrictions, as described in Section III.F.2.6.2(c), are equal to the sum of the non-VAR related Real-Time Posturing credits associated with restricting the output of a generating Resource for the weekly energy restriction period.

This Section III.F.2.6.5 shall be effective through September 30, 2012.

III.F.3. Charges for NCPC

III.F.3.1. Allocation.

The sum of Day-Ahead NCPC Credits for the Day-Ahead Energy Market, excluding the Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes, is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time NCPC Credits (excluding Posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Asset Related Demand Resources that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Asset Related Demand Resources for the Operating Day that result from operation in accordance with the ISO ’s instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic

Minimum Limit. Real Time NCPC Credits associated with the Posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit.

The sum of Day-Ahead Local Second Contingency Protection Resource NCPC Credits associated with generating Resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region in proportion to the daily sum of their Day-Ahead Load Obligations within each affected Reliability Region. The sum of Real-Time Local Second Contingency Protection Resource NCPC Credits associated with generating units identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region and, under certain circumstances, to any adjacent Control Area purchasing Emergency energy from the ISO. Charges are allocated in proportion to the daily sum of Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) Operation that is above its Minimum Consumption Limit) plus applicable Emergency energy sales within each affected Reliability Region.

The sum of Day-Ahead and Real-Time NCPC Credits paid to Market Participants associated with Resources other than SCRs (including Synchronous Condensers and Postured Resources) that have been identified by the ISO as being required to provide voltage support or VAR support are collected from Market Participants in accordance with Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Each Market Participant's Minimum Generation Emergency Charge is calculated as follows:

(1) For each generating Resource of the Market Participant for which a Minimum Generation Emergency Credit is calculated, subtract the Resource's Economic Minimum Limit from its Real-Time Generation Obligation and then multiply the result by the Market Participant's Ownership Share in the Resource. The sum of the results of such calculations shall be that Market Participant's Exempt Real-Time Generation Obligation.

(2) Subtract the sum of the Exempt Real-Time Generation Obligations for all Market Participants from the total Real-Time Generation Obligation of all Market Participants at Locations within the Reliability Region(s) for which a Minimum Generation Emergency was declared.

(3) Subtract the Market Participant's Exempt Real-Time Generation Obligation, as calculated in step (1) above, from its total Real-Time Generation Obligation within the Reliability Region(s) for which a Minimum Generation Emergency was declared, and then divide that result by the result in step (2).

(4) Multiply the total Minimum Generation Emergency Credit by the result in step (3). This result is the Market Participant's Minimum Generation Emergency Charge.

III.F.3.1.1. Allocation of Weekly Posturing Charges.

Real-Time NCPC Credits associated with the Posturing of facilities with weekly energy restrictions as determined pursuant to Section III.F.2.6.5 are allocated and charged to Market Participants in proportion to the sum of their Real-Time Load Obligations for the weekly energy restriction period, beginning with the first day in the weekly energy restriction period in which a Resource is postured through the last day of the period, or the day in which the actual restricted energy supply is exhausted, if earlier, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit.

This Section III.F.3.1.1 shall be effective through September 30, 2012.

III.F.3.2. Calculations

III.F.3.2.1 Day-Ahead NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total Day-Ahead NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead NCPC Credits, as previously calculated, for generating Resources, Postured generators (non-VAR) and Dispatchable Asset Related Demand (pumps only).

III.F.3.2.2 Local Second Contingency Protection Resource NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participants' Day-Ahead Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.3 VAR related NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total VAR related NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead VAR credits.

III.F.3.2.4 NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the NCPC Charges for the Day-Ahead Energy Market by allocating the total economic NCPC cost for the Day-Ahead Energy Market to each Market Participant based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub). For each External Node, if there are any Day-Ahead External Transaction purchase credits for each External Transaction purchase or Increment Offer cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Load Obligations at the External Node. If there are any Day-Ahead External Transaction sale credits for each External Transaction sale or Decrement Bid cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Generation Obligations at the External Node.

III.F.3.2.5 Local Second Contingency Protection Resource NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Day-Ahead Energy Market for each affected Reliability Region by allocating the total Local Second Contingency Protection Resource NCPC cost for the Day-Ahead Energy Market for each affected Reliability Region to each Market Participant within each affected Reliability Region based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations within the affected Reliability Region (not including the Hub).

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Day-Ahead Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External

Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.F.3.2.6 VAR Charges, Day-Ahead Energy Market, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the VAR Charges for the Day-Ahead Energy Market by allocating the sum of the total VAR related NCPC cost for the Day-Ahead Energy Market to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.7 Non-Synchronous Condenser related Economic NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total non-Synchronous Condenser related economic NCPC cost associated with the Real-Time Energy Market by summing all Market Participant's Real-Time NCPC Credits not related to Synchronous Condensers, as previously calculated, and the total Synchronous Condenser related NCPC cost (non-VAR related) associated with the Real-Time Energy Market by summing all Market Participants' non-VAR related Real-Time Synchronous Condenser related NCPC Credits for generating Resources, pool scheduled External Transaction purchases, pool- scheduled External Transaction sales and Dispatchable Asset Related Demand Resources (pumps only), cancelled Pool-Scheduled Resources excluding Resources Postured for reliability.

III.F.3.2.8 Local Second Contingency Protection Resource NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total Local Second Contingency Protection Resource NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.9 SCR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total SCR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time SCR NCPC Credits.

III.F.3.2.10 VAR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total VAR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time VAR credits including VAR credits associated with Synchronous Condensers and Postured generating Resources.

III.F.3.2.11 [Reserved.]

III.F.3.2.12 Real-Time Load Obligation Deviation.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1) by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub).

III.F.3.2.13 [Reserved.]

III.F.3.2.14 Real-Time Generation Obligation Deviation at External Nodes.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Generation Obligation Deviation at External Nodes by summing the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

III.F.3.2.15 Other.

The ISO calculates for each Operating Day the non-Postured non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related, non-Regulation and non-SCR related economic NCPC Charges for the Real-Time Energy Market for each Market Participant by allocating the total Real-Time non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related and non-SCR related NCPC cost to each Market Participant based on their daily pro-rata share of the daily sum of the following hourly Real-Time deviations:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resources Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following ISO Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following ISO Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1)
[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.
[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

plus,
(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.2.16 Local Second Contingency Protection Resource NCPC Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Real-Time Energy Market for each Market Participant within each affected Reliability Region by allocating the total Real-Time Local Second Contingency Protection Resource NCPC cost to each Market Participant within each affected Reliability Region based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Real-Time Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(a) For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, for hours in which there is a Local Second Contingency Protection Resource NCPC cost (as calculated in Section III.F.3.2.8) and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of proportional shares of Real-Time Load Obligations as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The proportionate share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
			Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-37 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line)	Vermont, Vermont Vermont West Central Massachusetts	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
			Massachusetts
	Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	West Central Massachusetts Connecticut	in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
1385 Cable External Node	Northport-Norwalk Harbor (1385 Line)	Connecticut	100% to Connecticut
Cross Sound Cable External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(b) For each month, the ISO performs an evaluation of total Real-Time Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph b, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only) above its Minimum Consumption Limit.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.3.2.17 VAR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the VAR Charges (including Synchronous Condensers) associated with the Real-Time Energy Market by allocating the total Real-Time VAR cost to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.18 SCR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the SCR Charges associated with the Real-Time Energy Market by charging the total Real-Time SCR cost to the appropriate entities based on Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

~~**SECTION III**~~

~~**MARKET RULE 1**~~

~~**APPENDIX H**~~

~~**OPERATIONS DURING COLD WEATHER CONDITIONS**~~

~~APPENDIX H~~

~~Operations During Cold Weather Conditions~~

~~Table of Contents~~

~~III.H.1 INTRODUCTION~~

~~III.H.2 DEFINITIONS AND INTERPRETATIONS~~

~~III.H.3 PROCEDURES~~

~~III.H.3.1 Natural Gas Industry Coordination~~

~~III.H.3.2 Reporting Anticipated Generating Resource Availability~~

~~III.H.3.3 Cold Weather Condition Evaluation~~

~~III.H.3.4 Cold Weather Condition Actions~~

~~III.H.3.5 [Reserved.]~~

~~III.H.3.6 [Reserved.]~~

~~III.H.3.7 [Reserved.]~~

~~Attachment 1 - [Reserved.]~~

~~III.H.1. INTRODUCTION~~

~~This Appendix H addresses system operations during Cold Weather Conditions. Appendix H includes provisions for coordination of the different scheduling timeframes between the gas and electric systems and the formal processes that need to exist among the ISO, owners of gas-fired generation and the natural gas industry during Cold Weather Conditions.~~

~~This **Appendix H** addresses ISO scheduling during Cold Weather Conditions that will allow natural gas units to receive their commitment status in sufficient time to purchase gas by the gas nomination deadline.~~

~~This **Appendix H** will provide electric scheduling certainty necessary to support Day-Ahead gas nominations by owners of natural gas units.~~

~~This **Appendix H** defines processes that will enable the ISO to forecast and operate with greater certainty and facilitate higher unit availability during Cold Weather Conditions.~~

~~This **Appendix H** includes definitions of key terms, responsibilities of Market Participants and the ISO, as well as rules for outage evaluation, outage requests and reporting.~~

~~III.H.2. DEFINITIONS AND INTERPRETATIONS~~

~~Whenever used in this Appendix H, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2.~~

~~For the purposes of this Appendix H, temperatures are the average of the temperatures obtained from the weather services for New England as described in the System Operating Procedure to Create Load Forecast, which is available on the ISO's website at http: www.isone.com/smd/system operating procedures.~~

~~III.H.3. PROCEDURES~~

~~III.H.3.1 [Reserved.]~~

~~III.H.3.2 Reporting Anticipated Generating Resource Availability~~

~~During a Cold Weather Watch, Cold Weather Warning or Cold Weather Event, Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the generating Resource's ability to procure fuel for the pertinent Operating Day and physical limitations that could reduce generating Resource output for the pertinent Operating Day.~~

~~**III.H.3.3 Cold Weather Condition Evaluation**~~

~~**(a) Develop Seven-Day Forecast.** Each day, the ISO develops a Seven-Day Forecast by 1100 in accordance with the current ISO New England System Rules. In addition to the requirements of the applicable ISO New England System Rules, the Seven-Day Forecast will include the following inputs:~~

- ~~A review of any notices issued by gas pipeline operators, communications with generating Resources, and an assessment of the potential unit availability impact of actions announced in those notices.~~
- ~~A review of forecasted weather conditions to determine if Cold Weather Conditions are forecast and an assessment of the potential impact of such weather conditions on natural gas unit availability.~~
- ~~A survey of dual fuel units normally operating on natural gas that have switched or are able to switch to their secondary fuel based on information received from each dual fuel generating Resource.~~

~~In the forecast process, the ISO will not change (based on the foregoing information) any data reflecting unit operating limits or unit availability unless requested by the Lead Market Participant for a generating Resource. However, the ISO may change such data reflecting unit operating limits or unit availability, in accordance with other Tariff provisions, ISO New England Operating Procedures or ISO New England Manuals, based upon information provided to the ISO by a Market Participant for a generating Resource.~~

~~**(b) Evaluate Seven-Day Forecast**. Each day during the Winter Capability Period, the ISO will evaluate the Seven-Day Forecast and perform a Cold Weather Conditions analysis for each day of the following seven-day period. By 1100 each day the ISO will post the Seven-Day Forecast and the applicable Cold Weather Condition for each day of the period.~~

~~The applicable Cold Weather Conditions are:~~

- ~~Cold Weather Watch~~
- ~~Cold Weather Warning~~
- ~~Cold Weather Event~~
- ~~No Cold Weather Condition applies~~

~~The Seven-Day Forecast will indicate, for each day, the anticipated reductions (MW) in total operable generating capacity resulting from the Cold Weather Conditions and the ISO may include the capacity (MW) of resources without a Capacity Supply Obligation (based on the historical offer trends) as operable generating capacity in the forecast. The ISO may update the Seven-Day Forecast and the Cold Weather Condition for each of day of the seven-day period at any time during the day. This process can result in declaration, reaffirmation or cancellation of the applicable Cold Weather Condition for any day in the forecast period subject to the limitations set forth in Section III.H.3.4(c)(i).~~

~~III.H.3.4 Cold Weather Condition Actions~~

~~(a) Cold Weather Watch~~

~~(i) Cold Weather Watch declarations:~~

- ~~Cold Weather Watch declarations will be made in advance for the following seven-day period as described in Section III.H.3.3.~~

- ~~If the ISO declares a Cold Weather Watch for specific days in the next seven-day period or revises an existing Cold Weather Condition to a Cold Weather Watch, a notice will be prominently posted on the ISO's website indicating the date(s) of a Cold Weather Watch.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Watch has been declared.~~

~~(b) Cold Weather Warning~~

~~(i) Cold Weather Warning declaration~~

- ~~Cold Weather Warning declarations will be made in advance for the following seven-day period as described in Section III.H.3.3.~~

- ~~If the ISO declares a Cold Weather Warning for specific days in the coming seven-day period or revises an existing Cold Weather Condition to a Cold Weather Warning, a notice will be prominently posted on the ISO's website indicating the date(s) of the Cold Weather Warning.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Warning has been declared.~~

~~(ii) Cold Weather Warning actions.~~

~~When a Cold Weather Warning is declared:~~

- ~~The ISO will request that all dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of Cold Weather Event days being declared.~~

- ~~The ISO will apply the procedures used in Master/Local Control Center Procedure #2 for the approval of transmission outage requests received for a day in the period for which a Cold Weather Warning has been forecast or declared.~~

~~(c) Cold Weather Event~~

~~(i) Cold Weather Event declaration~~

- ~~Cold Weather Event Declarations will normally be made no later than 1100 two days prior to the Operating Day unless circumstances require a later notice. Once a Cold Weather Event has been declared for a day of the up-coming seven-day period, it will not be cancelled.~~

- ~~If the ISO declares a Cold Weather Event for specific days, a notice will be prominently posted on the ISO's website indicating the date(s) of the Cold Weather Event, and all Supply Offers, Demand Bids, Increment Offers, Decrement Bids and all External Transactions normally required to be submitted by 1200 on [date] shall be due by 0900 on [date] Seven Day Forecast is posted on the ISO website.~~

- ~~The ISO will notify the Local Control Centers that a Cold Weather Event has been declared.~~

~~(ii) Cold Weather Event actions. When a Cold Weather Event is declared:~~

- ~~The ISO will communicate the Cold Weather Event to State Regulators, the Electric/Gas Operations Committee, members of the Markets, Reliability and Participants Committees, and Lead Market Participants, Designated Entities and Demand Designated Entities.~~

- ~~Public appeals and other actions of ISO New England Operating Procedure No. 4 will be implemented by the ISO as appropriate.~~

- ~~The ISO will communicate the potential for capacity shortage to other Control Areas and Reliability Coordinators, and will request their assistance if necessary.~~

- ~~The ISO will implement an alert under the provisions of Master/Local Control Center Procedure #2.~~

- ~~The ISO will request that Market Participants with dual-fueled units that normally burn natural gas to voluntarily switch to secondary fuel for Cold Weather Event Days. The ISO will communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to alternate fuel.~~

- ~~The ISO will change the Day-Ahead Energy Market trading deadline for Cold Weather Event days from 1200 to 0900 of the day prior to the Operating Day. Market Participants are responsible for submitting Supply Offers for the Day-Ahead Energy Market by the 0900 trading deadline. In connection with the submission of Supply Offers for each Cold Weather Event Operating Day, the Lead Market Participant of a generating Resource may re-declare the Resource's minimum run time and ramp rates to reflect limitations on the Resource's ability to receive gas off the pipeline due to gas pipeline operating limits but such re-declarations shall not exceed the period (generally the pertinent Gas Day) to which the gas pipeline operating limit applies.~~

- ~~Between 0900 and 1200 the Market User Interface (MUI) will be closed. The actions normally occurring at 1600 as described in Section III.1.10.8(b) of the Tariff and in ISO New England Manual M-11 will occur at 1200, including the posting of Day-Ahead Energy Market schedules and the opening of the Regulation market for offers.~~

- ~~After the submittal of Supply Offers and Demand Bids for the Day-Ahead Energy Market, the ISO will run the a Real-Time Resource Scheduling and Commitment (RT-RSC) Analysis, which will include the following inputs:~~

~~(i) The ISO load forecast~~

~~(ii) The Reserve Requirement established in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8~~

~~(iii) External Transactions forecast~~

~~(iv) Market Participant Supply Offers from generating Resources for the Day-Ahead Energy Market~~

~~(v) Assumptions with regard to the Real-Time operation of generating Resources that do not submit Supply Offers to the Day-Ahead Energy Market~~

~~(vi) Generation Requirement for Transmission (GRT) spreadsheet information~~

~~(vii) Must-Run Generation for VAR, Special Constraint Resources, and local transmission (emergency work)~~

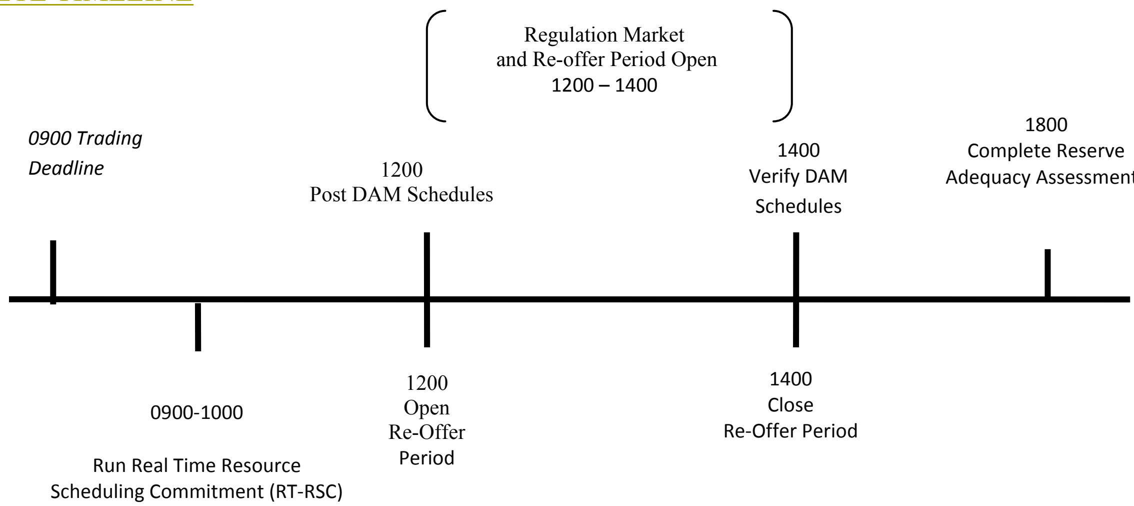
~~(viii) Available Dispatchable Asset Related Demand Resources~~

- ~~Between 0900 and 1000 the day prior to the Operating Day, Market Participants with gas-fired generating Resources that are determined by this evaluation to be necessary to meet load forecast and Reserve Requirements in accordance with Operating Procedure No. 8, will be advised (simultaneously, to the extent feasible) that they will be pool-scheduled in the Day-Ahead Energy Market for a specified minimum set of hours and MW levels.~~

- ~~The Re-Offer Period described in Section III.1.10.9(a) of the Tariff and normally occurring between 1600 and 1800 will instead occur between 1200 and 1400. During the Re-Offer Period, a Market Participant with a generating Resource may re-declare the Resource's ramp rate to reflect limitations on its ability to take gas off the pipeline due to gas pipeline operating limits. Such re-declarations~~

~~shall apply only to the gas days to which the gas pipeline operating limits apply. The above schedule is illustrated below. More detailed descriptions of the non-Cold Weather Event timeline may be found in ISO New England Manual M-11.~~

DELETE TIMELINE



- ~~Market Participants responsible for gas-fired generating Resources that are scheduled in the Day-Ahead Energy Market or that were advised by the ISO that their Resources will be committed for reliability purposes as determined by the RT-RSC shall provide to the ISO as soon as practicable but in no event later than the close of the Re-Offer Period evidence of and confirmation of gas volume nominations sufficient to deliver the energy scheduled for such Resource.~~

- ~~The information that is received by the ISO about gas-fired adequacy assessment process will be used in subsequent executions of the reserve adequacy assessment process.~~

- ~~As part of the reserve adequacy assessment process that takes place between 1400 and 1800, and as necessary throughout the Operating Day, the ISO will review the then-current gas nomination information as posted on the natural gas pipeline's Electronic Bulletin Board to better understand the overall New England gas supply situation. The ISO will, to the extent reasonably feasible, contact Market Participants responsible for generating Resources as needed to address concerns that result from the ISO's review of nomination information. This information will be used in performing the reserve adequacy assessments.~~

- ~~In the reserve adequacy assessment process, the ISO will change Operating Limits or Resource availability only in accordance with ISO Operating Documents or if such a change is requested by the Market Participant responsible for the generating Resource.~~

- ~~The ISO will provide through the 2200 forecast in accordance with III.13.1.4.4.1 an indication that Real-Time Demand Response Resources may be activated.~~

- ~~The ISO will dispatch Real-Time Emergency Generation Resources if and when the ISO reaches the applicable actions of ISO New England Operating Procedure No. 4.~~

~~III.H.3.5 [Reserved.]~~

~~III.H.3.6 [Reserved.]~~

~~III.H.3.7 [Reserved.]~~

~~Attachment 1~~

~~[Reserved]~~

ISO new england

memo

To: Participants Committee

From: Alex Kuznecow, Secretary, Markets Committee

Date: December 13, 2012

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 December 11 and 12, 2012 meeting. All Sectors had a quorum.

1. (Agenda Item 1A) **OCTOBER 10 & 11, 2012 MC MEETING MINUTES**
ACTION: APPROVED

It was moved, seconded and unanimously approved by the Markets Committee on a show of hands to accept the minutes of the October 10th and 11th Markets Committee meeting.

2. (Agenda Item 1B) **MARKETS COMMITTEE VICE-CHAIR ELECTION**
ACTION: APPROVED

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

> RESOLVED, that the Markets Committee hereby re-elects Thomas Kaslow for 2013 to the office of Vice-Chair to serve until his successor is elected and qualified.

The motion was then voted. Based on a show of hands, the motion passed unanimously.

3. (Agenda Item 2) **FINANCIAL ASSURANCE AND BILATERAL TRANSACTIONS – CONFORMING MANUAL CHANGES**
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 ISO New England Manuals M-11, M-28 and M-35 to conform to the Market Rule 1 language eliminating Internal Bilateral Transactions for the Regulation Market as proposed by ISO New England Inc. (the "ISO") and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed unanimously.

4. (Agenda Item 3) **DAY-AHEAD ENERGY MARKET TIMING**
ACTION: RECOMMEND SUPPORT

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

> RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Tariff Section I.2.2 and deletion of Appendix H to Market Rule 1 to implement a shift in the Day-

Ahead Energy Market and Reserve Adequacy Assessment timelines 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.

(**<u>Vote 1 – Failed</u>** *<u>(Vitol Amendment</u>*) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Tariff Section I.2.2 Definition "Re-Offer Period" by changing "1:00" to "2:30" within the definition.
(2) Revise the ISO proposed Section III.1.10.1A (Day-Ahead Energy Market Scheduling) of Market Rule 1 by changing "9:00" to "10:30" within the first paragraph.
(3) Revise the ISO proposed Section III.1.10.8 (b) (ISO Responsibilities) of Market Rule 1 by changing "12:30" to "2:00".
(4) Revise the ISO proposed Section III.1.10.9 (a) (Hourly Scheduling) of Market Rule 1 by changing "1:00" to "2:30".
(5) Revise the ISO proposed Section III.A.3.1 (Consultation) of Appendix A to Market Rule 1 by changing "5:00" to "6:00".

The motion to amend was then voted. The motion to amend failed with a vote of 44.43% in favor. The individual Sector votes were Generation (12.83% in favor, 4.27% opposed, 3 abstentions), Transmission (0% in favor, 17.1% opposed, 4 abstentions), Supplier (17.1% in favor, 0% opposed, 1 abstention), Alternative Resources (14.5% in favor, 0% opposed, 4 abstentions), Publicly Owned Entity (0% in favor, 0% opposed, 30 abstentions), and End User (0% in favor, 17.1% opposed, 6 abstentions).

(**<u>Vote 2 – Passed</u>** *<u>(Exelon Amendment</u>*) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the ISO proposed Tariff Section I.2.2 Definition "Re-Offer Period" by changing "1:00" to "2:00" within the definition.
(2) Revise the ISO proposed Section III.1.10.1A (Day-Ahead Energy Market Scheduling) of Market Rule 1 by changing "9:00" to "10:00" within the first paragraph.
(3) Revise the ISO proposed Section III.1.10.8 (b) (ISO Responsibilities) of Market Rule 1 by changing "12:30" to "1:30".
(4) Revise the ISO proposed Section III.1.10.9 (a) (Hourly Scheduling) of Market Rule 1 by changing "1:00" to "2:00".
(5) Revise the ISO proposed Section III.A.3.1 (Consultation) of Appendix A to Market Rule 1 by changing "5:00" to "6:00".

The motion to amend was then voted. The motion to amend passed with a vote of 70.55% in favor. The individual Sector votes were Generation (13.3% in favor, 3.8% opposed, 2 abstentions), Transmission (0% in favor, 17.1% opposed, 4 abstentions), Supplier (17.1% in favor, 0% opposed, 2 abstentions), Alternative Resources (14.5% in favor, 0% opposed, 4 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 2 abstentions), and End User (8.55% in favor, 8.55% opposed, 6 abstentions).

(**<u>Vote 3 – Failed</u>** *<u>(Brookfield Amendment</u>*) Before the amended main motion could be voted, it was moved and seconded by the Markets Committee to amend the amended main motion as follows:

(1) Revise the ISO proposed Tariff Section I.2.2 definition "Re-Offer Period" as follows:

> **Re-Offer Period** is the period of at least one hour, that normally occurs between the posting of the Day-Ahead Energy Market results and ~~1:00~~2:30 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.

The motion to amend the amended motion was then voted. The motion to amend failed with a vote of 28.5% in favor. The individual Sector votes were Generation (11.4% in favor, 5.7% opposed, 8 abstentions), Transmission (0% in favor, 17.1% opposed, 2 abstentions), Supplier (17.1% in favor, 0% opposed, 22 abstentions), Alternative Resources (0% in favor, 0% opposed, 7 abstentions), Publicly Owned Entity (0% in favor, 17.1% opposed, 3 abstentions), and End User (0% in favor, 17.1% opposed, 9 abstentions).

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

(1) Revise the ISO proposed Tariff Section I.2.2 Definition "Re-Offer Period" by changing "1:00 p.m." to "9:00 a.m." within the definition.
(2) Revise the ISO proposed Section III.1.10.1A (Day-Ahead Energy Market Scheduling) of Market Rule 1 by changing "9:00" to "5:00" within the first paragraph.
(3) Revise the ISO proposed Section III.1.10.8 (b) (ISO Responsibilities) of Market Rule 1 by changing "12:30 p.m." to "8:30 a.m.".
(4) Revise the ISO proposed Section III.1.10.9 (a) (Hourly Scheduling) of Market Rule 1 by changing "1:00 p.m." to "9:00 a.m.".
(5) Revise the ISO proposed Section III.A.3.1 (Consultation) of Appendix A to Market Rule 1 by changing "5:00" to "1:00".

The motion to amend the amended motion was then voted. The motion to amend failed with a vote of 15.19% in favor. The individual Sector votes were Generation (3.42% in favor, 13.68% opposed, 1 abstention), Transmission (8.55% in favor, 8.55% opposed, 2 abstentions), Supplier (0.78% in favor, 16.32% opposed, 2 abstentions), Alternative Resources (0% in favor, 14.5% opposed, 4 abstentions), Publicly Owned Entity (0% in favor, 17.1% opposed, 1 abstention), and End User (2.44% in favor, 14.66% opposed, 3 abstentions).

(**Vote 5 – Passed**) The amended main motion was then voted. The amended main motion passed with a vote of 84.8% in favor. The individual Sector votes were Generation (13.3% in favor, 3.8% opposed, 2 abstentions), Transmission (5.7% in favor, 11.4% opposed, 2 abstentions), Supplier (17.1% in favor, 0% opposed, 2 abstentions), Alternative Resources (14.5% in favor, 0% opposed, 4 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 2 abstentions), and End User (17.1% in favor, 0% opposed, 6 abstentions).

5. (Agenda Item 3) **DAY-AHEAD ENERGY MARKET TIMING ACTION: VOTE FAILED**

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO proposed revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Tariff Section I.2.2 and deletion of Appendix H to Market Rule 1 to implement a shift in the Day-Ahead Energy Market and Reserve Adequacy Assessment timelines.

The Markets Committee action on the ISO proposed revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Tariff Section I.2.2 and deletion of Appendix H to Market Rule 1 resulted in a vote of 43.05% in favor. The individual Sector votes were Generation (3.8% in favor, 13.3% opposed, 2 abstentions), Transmission (17.1% in favor, 0% opposed), Supplier (0.78% in favor, 16.32% opposed, 2 abstentions), Alternative Resources (0% in favor, 14.5% opposed, 4 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 28 abstentions), and End User (4.28% in favor, 12.82% opposed, 6 abstentions).

6. (Agenda Item 7) **PRICE-RESPONSIVE DEMAND FULL INTEGRATION UPDATES ACTION: RECOMMEND SUPPORT**

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

> RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1, Appendix E to Market Rule 1, and Tariff Section I.2.2 to implement the price-responsive demand full integration updates 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 opposition within the Generation Sector, 1 opposition within the Supplier Sector, 2 oppositions within the Alternative Resources Sector, and 3 oppositions within the End User Sector were recorded.

7. (Agenda Item 11) **NEPOOL GENERATION INFORMATION SYSTEM (GIS) REVISIONS ACTION: REFERRED TO WORKING GROUP**

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

(1) Consider potential changes to the NEPOOL GIS and the related provisions of the NEPOOL GIS Operating Rules relating to the treatment of GIS Certificates associated with net metering facilities.

Markets Committee
mc_actions_12121112

Vitol Amendment

SECTION I – GENERAL TERMS AND CONDITIONS

I.2.2. Definitions:

Re-Offer Period is the period that normally occurs between the posting of the Day-Ahead Energy Market results and ~~1:00~~ 2:30 p.m.~~16:00 and 18:00~~ 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.

~~consistent with the period (generally the pertinent Gas Day) to which the natural gas pipeline operating limit applies.~~

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than ~~9:00~~10:30 a.m.~~12:00 noon~~ on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than ~~4:00~~ ~~12:30~~ 2:00 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource ~~re-offer period~~Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until ~~1:00~~ 2:30 ~~4:00 p.m. to 6:00~~ p.m. on the day before each Operating Day or such other ~~re-offer period~~Re-Offer Period as necessary to account for software failures or other events. During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the ~~re-offer period~~Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is

Vitol Amendment

I.2.2. DEFINITIONS:

Reference Level is defined in Section III.A.~~5.6.1~~7 of Appendix A of Market Rule 1.

SECTION III

MARKET RULE 1

APPENDIX A

**MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION**

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources.

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, ~~and~~ 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. Market Participant requests to alter a Reference Level must be submitted to imm@iso-ne.com.

III.A.3.1. Consultation ~~Prior to Offer~~.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor no later than 90 minutes after the submission deadline for ~~at least one hour prior to the close of~~ the Day-Ahead Energy Market ~~offer deadline~~. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period ~~of the Real-Time Energy Market,~~ the Market Participant must contact the Internal Market Monitor no later than 30 minutes after ~~at least one hour prior to~~ the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by 6:00 ~~5:00~~ p.m. the day prior to the Operating Day. 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

Vitol's Proposed Tariff Amendments for ISO New England's Day-ahead Energy Market Timeline

Presented by Vitol Inc.

NEPOOL Markets Committee
December 11, 2012

Vitol's Proposed Tariff Amendments

- *DA Energy Market Timeline*
  - *Section I, General Terms and Conditions – 1.2.2 Definitions: changed "1:00" to "2:30" within the definition of "Re-Offer Period" (page 1)*
  - *Section III, Market Rule 1 – III.1.10.1A Day-Ahead Energy Market Scheduling: changed "9:00" to "10:30" within the first paragraph (page 4)*
  - *Section III, Market Rule 1 – III.1.10.8 ISO Responsibilities, paragraph (b): changed :12:30" to "2:00" (page 15)*
  - *Section III, Market Rule 1 – III.1.10.9 Hourly Scheduling, paragraph (a): changed "1:00" to "2:30" (page 15)*
- *Market Monitoring*
  - *Section III, Market Rule 1, Appendix A – III.A.3.1 Consultation: changed "5:00 p.m." to "6:00 p.m."*

EquiPower Amendment

SECTION I – GENERAL TERMS AND CONDITIONS

I.2.2. Definitions:

Reference Level is defined in Section III.A.~~5.6.1~~7 of Appendix A of Market Rule 1.

Re-Offer Period is the period that normally occurs between the posting of the Day-Ahead Energy Market results and ~~10:00~~9:30 ~~p~~a.m. ~~16:00 and 18:00~~ 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.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 5:00 a.m.~~12:00 noon~~ on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction

Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than ~~4:00~~8:30 a~~p~~.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource ~~re-offer period~~Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until ~~1:00~~9:30 a.m. ~~4:00 p.m. to 6:00 p.m.~~ on the day before each Operating Day or such other ~~re-offer period~~Re-Offer Period as necessary to account for software failures or other events. During the ~~re-offer period~~Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the

MARKET MONITORING,

REPORTING AND MARKET POWER MITIGATION

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources.

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, ~~and~~ 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. Market Participant requests to alter a Reference Level must be submitted to imm@iso-ne.com.

III.A.3.1. Consultation ~~Prior to Offer~~.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor no later than 90 minutes after the submission deadline for ~~at least one hour prior to the close of~~ the Day-Ahead Energy Market ~~offer deadline~~. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period ~~of the Real-Time Energy Market,~~ the Market Participant must contact the Internal Market Monitor no later than 30 minutes after ~~at least one hour prior to~~ the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment analyses if received by ~~5:00 p.m.~~ 1:00 p.m. the day prior to the Operating Day. 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

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Brookfield Energy Marketing Amendment

SECTION I – GENERAL TERMS AND CONDITIONS

I.2.2. Definitions:

Re-Offer Period is the period of at least one hour, that normally occurs between the posting of the Day-Ahead Energy Market results and 2~~1~~:~~0~~30 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.

Hotel restaurant will have limited hours during the holidays. Please call the hotel for specific days and times.

DOUBLETREE BY HILTON

Search

MAPS & DIRECTIONS

PRINT SHARE

DoubleTree by Hilton Hotel Boston - Westborough

5400 Computer Drive, Westborough, Massachusetts, 01581, USA
TEL: 1-508-366-5511

Parking

Self parking
(Complimentary)

Valet parking
Not Available

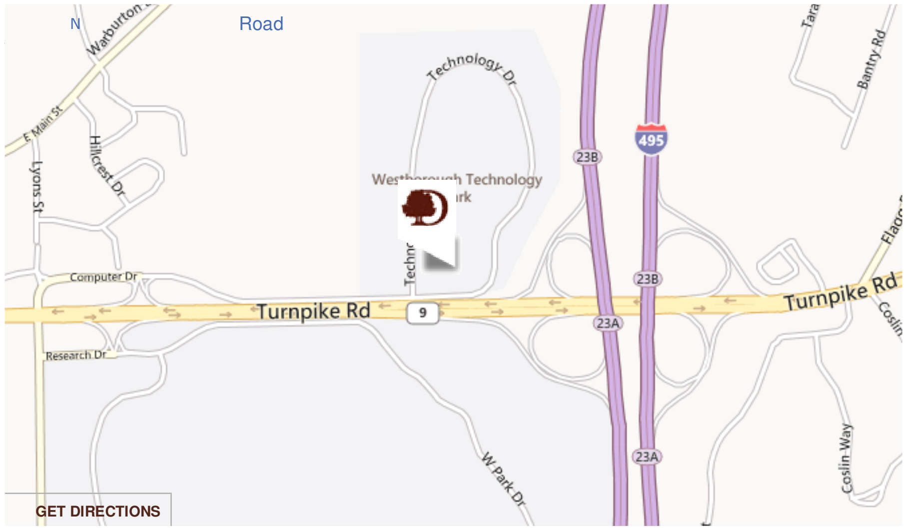
Secured
Not Available

Covered
Not Available

In/Out Privileges
Available

Other Parking Information
Parking Lot

Hotel Policies



GET DIRECTIONS

Directions from the Hotel Staff

From Worcester: Route 9 East to Computer Drive/Research Drive Exit. Take a right at the first set of lights onto New Flanders Road; bear right onto Computer Drive, head straight through the third set of lights, drive 1/2 miles and the hotel is on the left at the top of the hill.

From Sturbridge: Mass Turnpike (I-90) East to Exit 11A, I-495 North to Exit 23B (Route 9 West) to Computer Drive/Research Drive Exit. Bear right at the end of the ramp, drive 1/2 mile and the hotel is on the left at the top of the hill.

From I-495 North or South: Exit 23B (Route 9 West) to Computer Drive Research Drive Exit, bear right at the end of the ramp. Drive 1/2 mile and the hotel is on the left at the top of the hill.

From Connecticut: Route 84 North to Mass Turnpike (I-90) East to Exit 11A (Route 495), Route 495 North to Exit 23B (Route 9 West) to Computer Drive/Research Drive Exit. Bear right at the end of the ramp, drive 1/2 mile and the hotel is on the left at the top of the hill.

How to Get Here

From the Airport