March 24, 2010

VIA HAND DELIVERY

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ISO New England Inc. and New England Power Pool,
Docket No. ER10-___-000; Clarification of Market Settlement Rules

Dear Secretary Bose and Deputy Secretary Davis:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. (the "ISO") and the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties") hereby jointly submit an original and five copies of this transmittal letter and revised tariff sheets that clarify certain provisions of Market Rule 1[2] and its appendices related to the settlement of the competitive wholesale electricity market in New England (*i.e.* the "Market Settlement Clarifications"). In support of the Market Settlement Clarifications, this filing also includes the joint testimony of Jinye Zhao, Senior Analyst, Business Architecture and Technology, and Shannon L. Hann, Director, Market Analysis & Settlements, which is sponsored solely by the ISO (the "Zhao/Hann Testimony").

The Filing Parties request that the Market Settlement Clarifications become effective June 1, 2010 to coincide with the effectiveness of a number of other tariff changes associated with the beginning of the first FCM Capacity Commitment Period that also will become effective on June 1st.

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[1] 16 U.S.C. § 824d (2006 and Supp. II 2009).

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 ("ISO Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement. Market Rule 1 is Section III of the ISO Tariff.

I. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, the ISO also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 420 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Process for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the [ISO] Tariff, [Transmission Operating Agreement] and the Market Participant Services Agreement included in the [ISO] Tariff."

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO and NEPOOL as follows:

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II. STANDARD OF REVIEW

The instant revisions are submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[4] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[5] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[6] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[7] The revision "need not be the only reasonable methodology, or even the most accurate."[8] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[9]

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[3] Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203 of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

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

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

[6] *Id.*

[7] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

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

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

III. BACKGROUND

In the course of administering the financial settlement of the competitive wholesale electricity market in New England, the ISO's Market Analysis & Settlements department identified a number of non-substantive changes that should be made to the existing settlement provisions of the market rules. As explained in the Zhao/Hann Testimony, the clarifying changes are not intended to substantively change the manner in which settlement charges and credits are calculated, but rather are simply intended to ensure that the market rules provide greater clarity and guidance for Market Participants that participate in New England's competitive wholesale electricity market.

IV. DESCRIPTION OF THE MARKET SETTLEMENT CLARIFICATIONS

The Zhao/Hann Testimony summarizes the Market Settlement Clarifications[10] and also provides, as Exhibit A, a table explaining the changes in more detail. The clarifications generally address seven distinct settlement-related issues, most of which relate to Net Commitment Period Compensation ("NCPC") calculations.[11] As explained in the testimony, many of the changes ensure that certain provisions of Market Rule 1, Appendix F more clearly reflect the previously approved market rule changes regarding the eligibility of virtual transactions for NCPC credits that were submitted by the ISO in Docket No. ER09-547 on January 15, 2009 and accepted by the Commission by letter order dated February 12, 2009.[12] The changes also remove certain obsolete and inoperable provisions relating to day-ahead local second contingency protection NCPC costs, External Transactions and the defined term Effective Offer Price.[13]

As explained in the Zhao/Hann Testimony, the intent of all of the changes included in the Market Settlement Clarifications is simply to remove ambiguity and inaccuracies in the applicable tariff sheets so that the market rules will provide greater clarity and guidance for Market Participants and other stakeholders in New England's competitive wholesale electricity market.[14]

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[10] Zhao/Hann Testimony at 2-3.

[11] *Id*. at 3.

[12] *Id*.

[13] *Id*. at 3-4.

[14] *Id*. at 4.

V. STAKEHOLDER PROCESS

The NEPOOL Markets Committee, at its February 9, 2010 meeting, voted unanimously to recommend NEPOOL Participants Committee support for the Market Settlement Clarifications. The NEPOOL Participants Committee unanimously approved the Market Settlement Clarifications at its March 5, 2010 meeting as part of its Consent Agenda.[15]

VI. REQUESTED EFFECTIVE DATE AND ORDER ISSUANCE

The Filing Parties request an effective date of June 1, 2010 for the proposed revisions.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[16] However, the Market Settlement Clarifications are not traditional "rates," and the Filing Parties are not traditional investor-owned utilities. In light of these circumstances, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13, and request a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

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

- This transmittal letter;
- Blacklined Tariff Sheets reflecting the revisions proposed by this filing (Attachment 1);
- Clean Revised Tariff Sheets reflecting the revisions proposed by this filing (Attachment 2);

[15] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's approval of the March 5, 2010 Consent Agenda included its support for the Market Settlement Clarifications.

[16] 18 C.F.R. § 35.13 (2009).

- Joint Testimony and exhibit of Jinye Zhao, Senior Analyst, Business Architecture and Technology and Shannon L. Hann, Director, Market Analysis & Settlements, sponsored solely by the ISO (Attachment 3); and

- List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities, to which a copy of this filing has been sent (Attachment 4).

35.13(b)(2) - The Filing Parties request that the revisions become effective June 1, 2010.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpnts_eserved.pdf. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in Attachment 4. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Attachment 4 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in Section VI of this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Section IV of this transmittal letter.

35.13(b)(6) - The ISO's approval of the revision is evidenced by this filing. With respect to NEPOOL's approval, as noted in Section V of this transmittal letter, these changes reflect the support of the Participant Processes required by the Participants Agreement, having been approved by the NEPOOL Participants Committee by a show of hands, with oppositions and abstentions noted.

35.13(b)(7) – The Filing Parties do not have knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

VIII. CONCLUSION

For the reasons stated herein, the Filing Parties respectfully request that the Commission accept the Market Settlement Clarifications as filed, without condition, suspension, or hearing, to be effective June 1, 2010.

Please acknowledge receipt of the foregoing by date-stamping the enclosed extra copies of this filing and returning them to the courier delivering this filing.

Respectfully submitted,

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By: _____ /DRS

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Attachment 1

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

~~**Effective Offer Price** is defined in Sections III.3.2.3 (l), (m), and (n).~~

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.2 on a date after the addition or modification already has been otherwise identified in the current ISO Transmission Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

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

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources is described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution~~normal Real-Time security-constrained economic Energy dispatch solution~~ for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both on-line and off-line) or for the provision of voltage or VAR support.

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

Pre-1997 PTF Rate is the transmission rate of a PTO determined in accordance with paragraph (5) of Schedule 9 to the OATT.

for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for the Day Ahead Energy Market:

(i) For each Pool-Scheduled generating Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start- Up and No-Load Fees and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, i~~I~~f the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F.

(e) At the end of each Operating Day, the following determinations shall be made:

(i) for each eligible hour for each synchronized Pool-Scheduled Resource of each Market Participant that

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.

III.F.2. NCPC Credits.

NCPC Credits ~~for Resources capable of providing Operating Reserve, Replacement Reserve or VAR support~~ 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.

(e) operational flags;

~~•Real-Time Emergency Conditions flag;~~

• 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.

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. ~~If the ISO declared an Emergency Condition (in this case has declared a New England Control Area–wide capacity shortage), the ISO limits this amount to $1,000/MWh multiplied by the sum for the Operating Day of the lesser of: (i) the generating Resource's actual metered output or (ii) the higher of the generating Resource's Desired Dispatch Point or Economic Minimum Limit for each hour of pool-scheduled operation.~~

(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:

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~~, provided further, however, that the limitation set forth in the foregoing proviso shall not apply where an External Transaction purchase has been flagged as a Local Second Contingency Protection Resource~~.

III.F.2.3.6 [Reserved.]~~Day-Ahead Credit Allocation~~. ~~For each External Node, the Day-Ahead External Transaction purchase Credits for each External Transaction purchase or Increment Offer cleared in each hour are allocated to the Day-Ahead External Transaction sales or Decrement Bids cleared in the hour at that External Node.~~

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:

~~(a)For each scheduled hour, if the External Transaction purchase is flagged as 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.~~

~~(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 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~~hourly positive deviations from~~ 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~~MWh hourly deviations from~~ 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.

~~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.]~~Day-Ahead Credit Allocation~~. ~~For each External Node, the Day-Ahead External Transaction sale Credits for each External Transaction sale or Decrement Bid cleared in each hour are allocated to the Day-Ahead External Transaction purchases or Increment Offers cleared in the hour at that External Node.~~

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 ~~scheduled~~ Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount~~MWh~~ 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 ~~scheduled~~ Real-Time transaction amount scheduled in excess of ~~hourly negative deviations from~~ 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

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

(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.3.2. 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, ~~Pool-Scheduled External Transaction Purchases,~~ Postured Generators (non-VAR) ~~and Pool-Scheduled External Transaction Sales~~ 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

~~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 the 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 Delist Bid or Administrative Export Delist Bid associated with the External Transaction sale.

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.]~~Real-Time Load Obligation Deviation within each Reliability Region~~. ~~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) within each~~

~~Reliability Region by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations within the Reliability Region (not including the Hub).~~

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

Attachment 2

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.2 on a date after the addition or modification already has been otherwise identified in the current ISO Transmission Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

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

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources is described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both on-line and off-line) or for the provision of voltage or VAR support.

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

Pre-1997 PTF Rate is the transmission rate of a PTO determined in accordance with paragraph (5) of Schedule 9 to the OATT.

for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for the Day Ahead Energy Market:

(i) For each Pool-Scheduled generating Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start- Up and No-Load Fees and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, if the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F.

(e) At the end of each Operating Day, the following determinations shall be made:

(i) for each eligible hour for each synchronized Pool-Scheduled Resource of each Market Participant that

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.

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.

(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.

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:

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

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

(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.3.2. 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 the 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 Delist Bid or Administrative Export Delist Bid associated with the External Transaction sale.

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

Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and NEPOOL Participants Committee	**)**	**Docket No. ER10-___-000**

JOINT TESTIMONY OF

JINYE ZHAO AND SHANNON L. HANN

I. INTRODUCTION

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

A: *Ms. Zhao.* My name is Jinye Zhao. I am a Senior Analyst in the Business Architecture and Technology group at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Ms. Hann. My name is Shannon L. Hann. I am the Director of Market Analysis & Settlements for the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: Please describe your work experience and educational background.

A: *Ms. Zhao.* I obtained a Bachelor of Science degree in Mathematics from East China Normal University in 2002 and a Master of Science degree in Mathematics from National University of Singapore in 2004. I received a Master of Engineering degree in Operations Research and Statistics and a Ph.D. degree in Mathematics from Rensselaer Polytechnic Institute in 2007. My specialty is modeling of energy markets using optimization and game theory. I joined the Market Development group at ISO in December

2007. Currently, I am a Senior Analyst in the Business Architecture and Technology group at ISO.

Ms. Hann. As the Director of Market Analysis & Settlements, I oversee the day-to-day functions of the department, including the Hourly Markets, Monthly Markets, ISO and Open Access Transmission Tariffs, Market Analysis and Reporting, and project planning and implementation. My responsibilities also include working with other ISO departments and stakeholders to develop new market rules and procedures, to assess the impact of rule changes on the Market Analysis & Settlements Department's operation, and to coordinate the implementation of market rule changes and business process improvements for the Market Analysis & Settlements Department. Previously, I held the position of Settlement and Finance Project Coordinator and was responsible for implementation of Standard Market Design for the Settlement and Finance Departments. I was also the Internal Auditor responsible for the SAS 70 and Interim Market Design audits. I hold a Bachelors Degree in Business Administration with a concentration in accounting from the University of Massachusetts. I am a Certified Public Accountant in the state of Massachusetts.

II. PURPOSE, SCOPE, AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: The testimony supports a number of clarifications to Market Rule 1 that generally relate to the settlement of the markets. The clarifications are not intended to substantively change the manner in which settlement charges and credits are

calculated, but rather are simply intended to provide greater clarity and guidance for Market Participants that participate in New England's competitive wholesale electricity market.

III. DESCRIPTION OF THE PROPOSED CLARIFICATIONS

Q: Please describe the proposed clarifications.

A: The proposed clarifications generally address seven distinct settlement-related issues, most of which relate to Net Commitment Period Compensation ("NCPC") calculations. The seven issues are as follows:

1. Clarifying Market Rule 1, Appendix F concerning the eligibility of virtual transactions for NCPC credits. The changes conform Appendix F to the market rule changes regarding the eligibility of virtual transactions for NCPC credits that were submitted by the ISO in Docket No. ER09-547 on January 15, 2009 and accepted by the Commission by letter order dated February 12, 2009.

2. Revising Market Rule 1, Appendix F to clarify ambiguity involving the allocation of day-ahead NCPC charges associated with External Nodes.

3. Clarify certain sections of Market Rule 1 and Appendix F regarding the interaction of daily and hourly settlement calculations for day-ahead first contingency protection (also called "economic") NCPC to conform to changes originally submitted in Docket No. ER09-547.

4. Removing an inoperable rule provision regarding day-ahead local second contingency protection NCPC costs and External Transactions.

5. Correct an inaccuracy in Section 2.4.7 of Appendix F concerning the calculation of the real-time bid amount associated with External Transaction sales for purposes of calculating real-time NCPC.

6. Modify several sections of Appendix F to more precisely describe certain calculations that currently refer to positive and negative deviations in an ambiguous manner.

7. Removal of inoperable provisions relating to a defined term, Effective Offer Price, which became inoperable pursuant to a rule change in 2006

All of these changes and a few other minor housekeeping changes are shown in detail in a table that is attached to this testimony as Exhibit 1. This table was used to help explain the proposed changes as part of the stakeholder review process.

Q: Why is the ISO proposing these changes?

A: All of the revised changes are non-substantive in nature and the intent of the changes is simply to remove ambiguity and inaccuracies in the applicable tariff sheets so that the market rules will provide greater clarity and guidance for Market Participants and others that are stakeholders in New England's competitive wholesale electricity market.

IV. CONCLUSION

Q: Does this conclude your testimony?

A: *Ms. Zhao.* Yes.

Ms. Hann. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 3/24/2010

Shannon L. Hann

Jinye Zhao

Issue 1: Include virtual transactions into the calculation of Day-Ahead NCPC credits at external nodes.

One of the rule changes approved by FERC on Jan 15 2009 is to "make virtual transactions eligible for NCPC credits".

As identified in item 1 – item 12, the existing language in some relevant sections in Appendix F has not been updated to include virtual transactions into the calculation and the eligibility of Day-Ahead NCPC credits at external nodes. The following changes are proposed to make Appendix F language consistent with the rule change.

Item	Tariff Sheet	Reasons for changes	Proposed changes
1	Section III.F.1, Sheet 8008	Increment Offers and Decrement Bids should be included for receiving NCPC credits at external nodes.	The text should read: "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,"
2	Section III.F.2, Sheet 8012	Increment Offers and Decrement Bids should be included for receiving NCPC credits at external nodes.	The text should read: "NCPC Credits ~~**for Resources capable of providing Operating Reserve, Replacement Reserve or VAR support**~~ 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**."
3	Section III.F.2.3, Sheet 8031	Together with Pool-Scheduled External Transaction Purchases, Increment Offers should be considered for the calculation of NCPC credits at external nodes.	The text should read: "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.**"
4	Section III.F.2.3.2, Sheet 8032	Increment Offers should be included in the retrieved information at external nodes.	The text should read: " (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**"
5	Section III.F.2.3.3, Sheet 8032	Increment Offers should be included in Day-Ahead Offer Amount Calculation at external nodes.	The text should read: "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."
6	Section III.F.2.3.4, Sheet 8032	Increment Offers should be included in Day-Ahead Value Calculation at external nodes.	The text should read: "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."
7	Section III.F.2.3.5, Sheet 8033	Increment Offers should be included in Day-Ahead Credit Calculation at external nodes.	The text should read: "The ISO calculates the hourly Day-Ahead Credits for each Pool-Scheduled External Transaction purchase **or Increment Offer at an External Node** as follows:"
8	Section III.F.2.4, Sheet 8036	Together with Pool-Scheduled External Transactions Sales, Decrement Bids should be considered for NCPC credits calculation at external nodes.	The text should read: "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.** "
9	Section III.F.2.4.2, Sheet 8038	Decrement Bids should be included in the retrieved information at external nodes.	The text should read: "(b) Pool-Scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction sales (positive values), **and Decrement Bids at External Nodes** (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**"
10	Section III.F.2.4.3, Sheet 8038	Decrement Bids should be included in the Day-Ahead Bid Amount Calculation at external nodes.	The text should read: "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."
11	Section III.F.2.4.4, Sheet 8038	Decrement Bids should be included in the Day-Ahead Cost Calculation at external nodes.	The text should read: "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."
12	Section III.F.2.4.5, Sheet 8039	Decrement Bids should be included in Day-Ahead Credits at external nodes.	The text should read: "The ISO calculates the hourly Day-Ahead Credits for each Pool-Scheduled External Transaction sale **or Decrement Bid at an External Node** as follows:"

Issue 2: Clarify the allocation of Day-Ahead NCPC charges associated with External Nodes

One of the rule changes approved by FERC on Jan 15 2009 is to "change the allocation of External Node NCPC charges from all Day-Ahead Load Obligations to the load at the external location as defined by prevailing flow". To reflect this rule change, Section III.F.2.3.6 and Section III.F.2.4.6 were revised and approved by FERC as follows :

Section III.F.2.3.6: For each External Node, the Day-Ahead External Transaction purchase Credits for each External Transaction purchase or Increment Offer cleared in each hour are allocated to the Day-Ahead External Transaction sales or Decrement Bids cleared in the hour at that External Node.

Section III.F.2.4.6: For each External Node, the Day-Ahead External Transaction sale Credits for each External Transaction sale or Decrement Bid cleared in each hour are allocated to the Day-Ahead External Transaction purchases or Increment Offers cleared in the hour at that External Node.

However, the revised language delivers a message that External Node NCPC **credits,** instead of charges, are allocated at the external location as defined by prevailing flow. To correct this error, language changes for these two sections are proposed in item 13 and item 14.

Moreover, the contents of Section III.F.2.3.6 and Section III.F.2.4.6 should be moved to Section III.F.3.2.4. This is because Section F.2 and its subsections address the rules related to NCPC credits while Section F.3 and its subsections address the rules related to NCPC charges and their allocation. The current Section III.F.2.3.6 and Section III.F.2.4.6 are related to the allocation of DA external node NCPC charges, so it is more appropriate to incorporate them in the Section F.3.2.4.

Item	Tariff Sheet	Reasons for changes	Proposed changes
13	Section III.F.2.3.6, Sheet 8033	The current language in Section III.F.2.3.6 indicates that if there are any DA external transaction **purchase credits**, External Transaction sales or Decrement Bids are able to receive these credits. However, according to the rule change, External Transaction sales or Decrement Bids are supposed to pay for DA external transaction purchase charges. Section III.F.2.3.6 needs to be rewritten to correct this issue. "to the Day-Ahead External Transaction sales or Decrement Bids cleared in the hour at that External Node" is replaced with "pro-rata to the hourly Day-Ahead Load Obligations at the External Node". This is because "Day-Ahead Load Obligations at the External Node" is a more precise way to describe "the Day-Ahead External Transaction sales or Decrement Bids cleared at that External Node".	The text should read: "For each External Node, **if there are any** ~~the~~ Day-Ahead External Transaction purchase Credits for each External Transaction purchase or Increment Offer cleared in each hour, **they** are allocated **and charged** ~~to the Day-Ahead External Transaction sales or Decrement Bids cleared in the hour at that External Node~~ **pro-rata to the hourly Day-Ahead Load Obligations at the External Node.**" The modified contents of III.F.2.3.6, Sheet 8033 will be moved to III.F.3.2.4, Sheet 8056.
14	Section III.F.2.4.6, Sheet 8039	The current language in Section III.F.2.4.6 indicates that if there are any DA external transaction **sale credits**, External Transaction purchases or Increment Offers are able to receive these credits. However, according to the rule change, External Transaction purchases or Increment Offers should pay for DA external transaction sale charges. Section III.F.2.4.6 needs to be rewritten to correct this issue. "to the Day-Ahead External Transaction purchases or Increment Offers cleared in the hour at that External Node" is replaced with "pro-rata to the hourly Day-Ahead Generation Obligations at the External Node". This is because "Day-Ahead Generation Obligations at the External Node" is a more precise way to describe "the Day-Ahead External Transaction purchases or Increment Offers cleared at that External Node".	The text should read: "For each External Node, **if there are any** ~~the~~ Day-Ahead External Transaction sale Credits for each External Transaction sale or Decrement Bid cleared in each hour, **they** are allocated **and charged** ~~to the Day-Ahead External Transaction purchases or Increment Offers cleared in the hour at that External Node~~ **pro-rata to the hourly Day-Ahead Generation Obligations at the External Node.**" The modified contents of III.F.2.4.6, Sheet 8039 will be moved to III.F.3.2.4, Sheet 8056.
15	Section III.F.3.2.4, Sheet 8056	Since Section III.F.2.3.6 and Section III.F.2.4.6 address **the allocation of NCPC charges** associated with External Nodes, it is more appropriate to place them in Section III.F.3.2.4. The contents of Section III.F.2.3.6 and Section III.F.2.4.6 are added to Section III.F.3.2.4. Section III.F.2.3.6 and Section III.F.2.4.6 are removed from Appendix F.	The text should read: "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."
16	Section III.3.2.3(d), Sheet 7176	According to the change, unlike the other Day-Ahead economic NCPC charges that are allocated **on a daily basis**, the Day-Ahead NCPC charges associated with an External Node are allocated to the load at that external node as defined by prevailing flow **on an hourly basis**. The existing language in Section III.3.2.3 (d) has not been updated to reflect the different allocation methods for Day-Ahead economic NCPC charges.	The text should read: "The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day-Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in a accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, **and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F.**"

Issue 3: Exclude external transactions (physical and virtual) from the calculation of the total Day-Ahead economic NCPC costs.

One of the rule changes approved by FERC on Jan 15 2009 is to "change the method for calculating and allocating NCPC at external locations from a 24-hour commitment period basis to an hour-by-hour basis".

This rule change indicates that Day-Ahead External Node NCPC credits are calculated on an hourly basis. In turn, Day-Ahead NCPC costs associated with External Nodes are determined and charged to applicable Market Participants on an hourly basis, while other Day-Ahead NCPC costs are calculated and charged on a daily basis. Because of the difference in settlement intervals, Day-Ahead NCPC credits associated with External Nodes should be excluded from the calculation of the **daily** total Day-Ahead economic NCPC costs. As identified in item 17 – item 19, the existing language in some relevant sections in Appendix F and Market Rule I has not been updated to except External Node NCPC credits from the calculation of **daily** Day-Ahead NCPC costs. The following changes are proposed to clarify this issue.

Item	Tariff Sheet	Reasons for changes	Proposed changes
17	Section III.F.3.1, Sheet 8052	Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes should be excluded from the calculation of the **daily** sum of Day-Ahead NCPC Credits.	The text should read: "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."
18	Section III.F.3.2.1, Sheet 8055	Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes should be excluded from the calculation of the **daily** total Day-Ahead NCPC cost. Delete "Pool-Scheduled External Transaction Purchases" and "and Pool-Scheduled External Transaction Sales"	The text should read: "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, ~~Pool-Scheduled External Transaction Purchases~~, Postured Generators (non-VAR) ~~and Pool-Scheduled External Transaction Sales~~ and Dispatchable Asset Related Demand (pumps only). "
19	Section III.3.2.3 (b) (i), Sheet 7174	The calculation of **daily** Day-Ahead NCPC credits should not be applied to external transactions (physical and virtual) at external nodes. Add "**Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F**" in front of "If the total offered price…".	The text should read: "**Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, if** the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating day, the difference shall be credited to the Market Participant."

Issue 4: Remove the language related to Day-Ahead Local Second Contingency Protection Resource NCPC costs associated with External Transactions.
Because External Transactions are never flagged as Local Second Contingency Protection Resources in the day-ahead market, it is proposed to remove the references to Day-Ahead Local Second Contingency Protection Resource NCPC at External Nodes.

Item	Tariff Sheet	Reasons for changes	Proposed changes
20	Section III.F.2.3.5, Sheet 8033	Remove the language related to Day-Ahead Local Second Contingency Protection Resource NCPC associated with External Transactions.	The text should read: "Day-Ahead Credits. The ISO calculates the hourly Day-Ahead Credits for each Pool-Scheduled External Transaction purchase or Increment Offer 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~~, provided further, however, that the limitation set forth in the foregoing proviso shall not apply where an External Transaction purchase has been flagged as a Local Second Contingency Protection Resource~~."
21	Section III.F.2.3.7, Sheet 8033	Remove the language related to Day-Ahead Local Second Contingency Protection Resource NCPC associated with External Transactions.	The text should read: "Day-Ahead NCPC Credits: Market Participant's Hourly Credits. The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credits 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 Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to the Day-Ahead Credit in that hour.~~ ~~(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 Day-Ahead economic NCPC Credits is equal to the Day-Ahead Credit in that hour."

Issue 5: Correct a misinterpretation regarding the Real-Time bid amount for External Transaction Sales

In Real-Time NCPC for External Transactions, the ISO settlement uses the amount of the Real-Time transaction scheduled in excess of the associated cleared Day-Ahead schedule to calculate the Real-Time bid amount. However, the existing language in section III.F.2.4.7 provided below indicates that the amount used in the calculation of the Real-Time bid

amount is only the scheduled Real-Time transaction.

"*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 scheduled Real-Time transaction MWh*** *by the transaction Demand Bid price.*"

The following change is proposed to correct this misinterpretation.

Item	Tariff Sheet	Reasons for changes	Proposed changes
22	Section III.F.2.4.7, Sheet 8039	The Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount, instead of the Real-Time transaction, should be used to calculate the Real-Time bid amount.	The text should read: "The ISO calculates the hourly Real-Time bid amount for each Pool-Scheduled External Transaction sale by multiplying the ~~**scheduled**~~ Real-Time transaction ~~**MWh**~~ **amount scheduled in excess of the cleared Day-Ahead transaction amount** by the transaction Demand Bid price".

Issue 6: Clarify the "negative/ positive deviations" language in the calculation of the external transactions Real-Time cost, Real-Time offer amount and Real-Time value

When calculating the Real-Time cost for an external transaction sale, the ISO settlement uses the amount of the Real-Time transaction that is scheduled to consume more than the associated cleared Day-Ahead schedule. Such amount is ambiguously referred to as "negative deviations" in the current language in Section III.F.2.4.9 as shown below.

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 scheduled Real-Time transaction hourly negative deviations from the cleared Day-Ahead transaction amount*** *by the Real-Time LMP of the applicable External Node.*

The term "negative deviations" is unclear, and could be clarified to better indicate that it is the amount of the Real-Time external transaction sale in excess of the cleared Day-Ahead amount. The proposed language is provided in item 23.

Similarly, the terms "positive deviations" and "deviations" used in Section III.F.2.3.8 (Real-Time Offer Amount for External Transaction Purchases) and Section III.F.2.3.9 (The Real-Time Value for External Transaction Purchases) are vague, and could be clarified to better indicate that they represent the amount of the Real-Time external transaction purchase in excess of the cleared Day-Ahead amount. The proposed language changes are presented in items 24 and 25.

Item	Tariff Sheet	Reasons for changes	Proposed changes
23	Section III.F.2.4.9, Sheet 8039	Replace "negative deviations" with a more explicit description.	The text should read: "The ISO calculates the hourly Real-Time cost for each Pool-Scheduled External Transaction sale by multiplying the ~~**scheduled**~~ Real-Time transaction **amount scheduled in excess of** ~~**hourly negative deviation from**~~ the cleared Day-Ahead transaction amount by the Real-Time LMP of the applicable External Node. "
24	Section III.F.2.3.8, Sheet 8034	Replace "positive deviations" with a more explicit description.	The text should read: "The ISO calculates the hourly Real-Time offer amount for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction ~~**MWh**~~ **amount that exceeds** ~~**hourly positive deviations from**~~ the cleared-Day-Ahead schedule by the transaction offer price."
25	Section III.F.2.3.9, Sheet 8034	Replace "deviations" with a more explicit description.	The text should read: "The ISO calculates the hourly Real-Time value for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction ~~**MWh**~~ **amount that exceeds** ~~**hourly deviations from**~~ the cleared Day-Ahead transaction MWh amount by the Real-Time LMP of the applicable External Node."

Issue 7: Remove the language relevant to "Effective Offer Price"

In 2006, the "Effective Offer Price" cap was removed to allow generators the opportunity to recover costs that may exceed $1,000/MWh during Emergency Conditions.

As identified in items 5-8, the existing language that is relevant to "Effective Offer Price" should be removed to be aligned with the rule change.

Item	Tariff Sheet	Reasons for changes	Proposed changes
26	Section I.2, Sheet 15Q	Remove the definition of "Effective Offer Price" in the Market Rule Section III.1.3.2 since it is no longer applicable.	~~"Effective Offer Price" is defined in Sections III.3.2.3 (l), (m), and (n).~~
27	Section III.F.2.1.14 (a), Sheet 8026	Remove the language reflecting the concept of "Effective Offer Price" since it is no long applicable.	III.F.2.1.14 (a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day. ~~**If the ISO declared an Emergency condition (in this case has declared a New England Control Area- wide capacity shortage), the ISO limits this amount to $1,000/MWh multiplied by the sum for the Operating Day of the lesser of: (i) the generating Resource's actual metered output or (ii) the higher of the generating Resource's Desired Dispatch Point or Economic Minimum Limit for each hour of pool-scheduled operation.**~~
28	Section III.F.2.1.1 (e), Sheet 8015	Since "Effective Offer Price" needs to be removed, it is not necessary to retrieve "Real-Time Emergency Conditions flag" which is used to identify Emergency Conditions. Remove "Real-Time Emergency Conditions flag" from the "Information Retrieved" section.	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; ~~• **Real-Time Emergency Conditions flag;**~~ • 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).
29	Manual 35 Definitions and Abbreviations, Page 1-18	Remove the definition of "Effective Offer Price" in Manual 35 since it is no longer applicable.	~~**Effective Offer Price**~~ ~~**For the Real-Time Energy Market, the Effective Offer Price shall be the amount calculated for total offered price for such Operating Day pursuant to Section III.3 of Market Rule 1 divided by the lesser of (i) hourly metered output or (ii) requested output as determined by the ISO dispatch, during the pool-scheduled hours determined under Section III.3 of Market Rule 1. For the Day-Ahead Energy Market, the Effective Offer Price shall be the amount calculated for total offered price for such Operating Day pursuant to Section III.3 of Market Rule 1 divided by the scheduled MWh during the pool-scheduled hours determined under Section III.3 of Market Rule 1. [Market Rule 1]**~~

Other issues			
Item	Tariff Sheet	Reasons for changes	Proposed changes
30	Section III.1.3.2, Sheet 7046A	The current definition of "Posture" is based upon the version of the Market Rule that was filed pre-ASM Phase II, which did not establish the co-optimization of energy and operating reserves in Real-Time. In the definition of "Posture", the language should be updated to "**jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution**" from "**normal Real-Time security-constrained economic Energy dispatch solution**".	The text should read: ""Posture" shall mean an action of the ISO to deviate from ~~**the normal Real-Time security-constrained economic Energy dispatch solution**~~ **the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution** for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both on-line and off-line) or for the provision of voltage or VAR support."
31	Section III.F.3.2.13, Sheet 8059	Local Second Contingency Protection Resource (LSCPR) NCPC cost used to be allocated **the RTLO Deviation** within the affected Reliability Region. In 2005, the Market Rule was changed to allocate the LSCPR NCPC to **the RTLO** within the affected Reliability Region. Remove Appendix F Section III.F.3.2.13 since this section is related to the Real-Time Load Obligation (RTLO) Deviation that is no longer applicable.	III.F.3.2.13 ~~**Real-Time Load Obligation Deviation within each Reliability Region. 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) within each Reliability Region by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations within the Reliability Region (not including the Hub).**~~ **Reserved**

Attachment 4

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and Related Agencies

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Hartford, CT 06106

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine

The Honorable John E. Baldacci
One State House Station
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Augusta, ME 04333-0001

Maine Public Utilities Commission
State House, Station 18
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Augusta, ME 04333-0018

Massachusetts

The Honorable Deval Patrick
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Rm. 360 State House
Boston, MA 02133

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110

New Hampshire

The Honorable John H. Lynch
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25 Capitol Street
Concord, NH 03301

New Hampshire Public Utilities Commission
21 South Fruit Street
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Rhode Island

The Honorable Donald L. Carcieri
State House Room 115
Providence, RI 02903

Rhode Island Public Utilities Commission
89 Jefferson Boulevard
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The Honorable James H. Douglas
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