David T. Doot
Secretary

February 26, 2010

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of March 5, 2010 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee will be held on **Friday, March 5, 2010 at 10:00 a.m. at the Boston Seaport Hotel and Conference Center, One Seaport Lane, Boston, MA.** The Participants Committee meeting will be held in the Seaport Ballroom, in the Seaport Hotel (not in the World Trade Center Building), for the purposes set forth on the attached agenda. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

Directions to the Seaport Hotel are included with this notice. Rooms at the Seaport Hotel for the March 5 meeting are available at the rate of $149.00 per night, on a first come, first served basis **UNTIL March 2, 2010.** To take advantage of these arrangements, please contact the hotel directly (617-385-4514) and reference the "NEPOOL Participants Committee" block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee meeting held on February 5, 2010. Draft minutes marked to show changes from the prior draft are included with this supplemental notice.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To consider and take action, as appropriate, on proposed conforming changes to credit reforms and market liquidity in response to FERC NOPR. Background material and a draft resolution are included with this supplemental notice**.**

5A. To consider and take action, as appropriate, on comments to FERC Notice of Inquiry regarding integration of variable energy resources (VER) into the wholesale electric grid. Background material and a draft resolution are included with this supplemental notice.

5B. To consider and take action, as appropriate, on comments in response to FERC staff's proposed RTO Metrics and Additional Information. Background material and a draft resolution are included with this supplemental notice.

6. ~~To consider and take action, as appropriate, on proposed changes to the Financial Assurance Policy relating to (i) procedures for banks that are non-compliant with letter of credit, (ii) changes in Market Rule 1, and (iii) resource terminations in the Forward Capacity Market. Background materials and a draft resolution(s) are included with this notice.~~

7. To consider and take action on proposed changes to ISO New England Operating Procedure Nos. 1 (Appendix A) and 14 (including Appendix 14A), and Planning Procedure Nos. 3, 5-1, and 5-3, associated with the NUC-001 Reliability Standards. Background material and a draft resolution are included with this supplemental notice**.**

8. To consider and take action, as appropriate, on proposed changes to Market Rule 1 Section 12.9 (Tie Benefits) in response to the February 12, 2010 FERC Order in Docket No. ER10-438-000 that directs the ISO to add language establishing a two-year sunset provision requiring the ISO to file Market Rule changes, as necessary, applicable to the third ARA for the 2012/2013 Commitment Period. Background material and a draft resolution are included with this supplemental notice.

8A. To consider and act on a report by the Membership Subcommittee concerning an application by the Town of New Shoreham (Block Island), Rhode Island to join NEPOOL as a Governance Only End User. Background material and a draft resolution are included with this supplemental notice.

9. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be circulated under separate cover.

10. To receive reports from committees and subcommittees.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held at 10:00 a.m. on Friday, February 5, 2010 at The Colonnade Hotel, 120 Huntington Avenue, Boston, MA, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Brian Forshaw, Chair, presided and Mr. David T. Doot, Secretary, recorded.

RECOGNITION OF ROBERT DE R. STEIN AND DONALD J. SIPE

Mr. Robert de Rochemont Stein was recognized for his tenure as Chairman of the Participants Committee for 2008 and 2009. Following introductory remarks of appreciation from Mr. Forshaw, the Committee approved the following resolution of appreciation by unanimous acclamation:

> *WHEREAS*, Mr. Robert de R. Stein was the Chairman of the New England Power Pool Participants Committee during 2008 and 2009; and
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> *WHEREAS*, in addition to his other duties in the Pool, Bob has been the elected representative of the Supplier Sector, offering guidance and leadership to that Sector with the interests of both his Sector and the Pool in focus, and has served previously as the elected officer of the Reliability Committee; and
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> *WHEREAS*, throughout his service as Chairman of the NEPOOL Participants Committee, Bob demonstrated professionalism, integrity, dedication, understanding, and a keen sense of fairness and statesmanship in addressing numerous controversial issues confronting NEPOOL; and
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> *WHEREAS*, Bob has long and diverse experiences in the New England electric industry, serving at various times during his career as NEPOOL staff, and as a representative for his employers or clients who were publicly owned entities, transmission owners, generators and suppliers. With the benefits of that broad perspective, clear thinking, and good humor, Bob has helped to guide the region through highly controversial issues while helping to maintain and nurture productive relationships among, and between, the NEPOOL members and their Sectors, with ISO New England, the New England Conference of Public Utilities

Commissioners and its members, the New England Committee on Electricity, and the Federal Energy Regulatory Commission; and

WHEREAS, Bob can fairly be credited with or blamed for (depending on perspective), key elements of FCM, the successful transformation of the interconnection queue to account for FCM, and many years of helping to work through whatever agreements were possible at the time on the region's capacity requirements and the Hydro-Quebec interconnection arrangements.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its gratitude to Bob for his years of service so far to the Pool as its Chairman and looks forward to continuing to work with him for many years to come.

Mr. Stein was presented with a copy of this resolution and some small gifts in appreciation for his years of service.

Mr. Forshaw then recognized Mr. Sipe for his service as the elected representative of the End User Sector. The following resolution of appreciation was then duly made, seconded, and approved by unanimous acclamation:

WHEREAS, Don represents the first Participant member of the End User Sector and served with distinction for the past nine years as the End User Sector's Participants Committee Officer; and

WHEREAS, during his tenure as Sector representative and officer, the End User Sector has blossomed to include more than 50 Participants and become the Sector with the third most individual voting members; and

WHEREAS, drawing from his experience as a regulator, a gymnastics coach, a landscaper, a waiter, and an epic poet, although not necessarily simultaneously, with equal success, or in that order, Don has been a valued source of guidance and leadership for the betterment of the End User Sector and the Pool; and

WHEREAS, throughout his service as the End User Sector's Officer, Don has demonstrated professionalism, integrity, dedication, understanding, and a keen sense of fairness and statesmanship in addressing the many controversial issues confronting the End User Sector, NEPOOL, and the New England region; and

WHEREAS, Don has been a catalyst for improving and reforming the region's governance arrangements and a champion of demand response initiatives.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its gratitude to Don for nine years of service as the elected representative of the End User Sector and looks forward to continuing to work with him for many years to come.

Mr. Sipe, also, was presented with a copy of this resolution and a small gift of appreciation acknowledging his many years of service and his affinity for epic poems.

APPROVAL OF JANUARY 8, 2010 MINUTES

Mr. Doot referred the members to the preliminary minutes for the January 8, 2010 meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the January 8 meeting, with minor editorial changes noted, were unanimously approved.

CONSENT AGENDA

Mr. Forshaw referred the Committee to the Consent Agenda that had been circulated in advance of the meeting, noting that Consent Agenda Item #3 had been removed to be addressed separately. Following motion duly made and seconded, the remaining items on the Consent Agenda were unanimously approved, with an abstention by GDF Suez.

REPORT OF ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie summarized the Board and Board Committee meetings that had occurred since his January 8 report. He noted that each of the committees and the Board met once.

Compensation and Human Resources Committee

Mr. van Welie reported that the Compensation and Human Resources Committee met on January 21 in Holyoke to discuss a variety of compensation-related matters. The Committee reviewed updated survey data on national trends regarding compensation, and concluded that the 2.5% merit and 0.5% promotional salary budget increases that were included in the ISO's 2010 budget remain at the lower end of the survey ranges. The Committee therefore approved use of these amounts for compensation purposes. In addition, the Committee received an update on negotiations with the union representing the ISO's system operators. The Committee also considered the ISO's experience to date with health insurance renewals and recommended the Board's adoption of a number of administrative amendments to the pension plans.

System Planning and Reliability Committee (SPARC)

The SPARC met on January 20 in Springfield. The Committee reviewed the union negotiations from a reliability perspective, including management's contingency planning in the event of a work stoppage. Next, the Committee received an update on renewable programs in New England and discussed a request from a Market Participant that the ISO take a proactive policy role in urging regional policymakers to modify renewable programs to locationally and temporally differentiate the energy credits for these resources. The Committee concluded that such policy matters are not in the ISO's purview but, instead, lie with state policymakers. The Committee also received an update on the ISO's Smart Grid grant from the Department of Energy and discussed generally the topic of non-transmission alternatives as part of the planning process. Finally, SPARC discussed compensation-related matters within its jurisdiction.

Audit and Finance Committee

Mr. van Welie reported that the Audit and Finance Committee met on January 21 in Holyoke. The Committee reviewed FERC's order on the 2010 administrative budget. The

Committee also discussed the transfer of pension investments to a new advisor. Last, the Committee considered compensation-related matters within its jurisdiction.

Board Markets Committee

Mr. van Welie went on to report that the Board Markets Committee met on January 21 in Holyoke. The Board Markets Committee received its regular reports on market monitoring activity, market seams, and the NEPOOL Markets Committee. Like other committees, the Board Markets Committee also considered compensation-related matters within its jurisdiction. That Committee, he reported, deferred its consideration of virtual trading and load forecasting accuracy improvements to a future meeting, in order to have sufficient time to discuss the Forward Capacity Market (FCM) and the Price-Responsive Demand (PRD) programs. For both FCM and PRD, Mr. van Welie reported that management had presented the Board Markets Committee with substantial advance information regarding stakeholders' positions and management's recommendations. Regarding FCM, the Committee reviewed the proposals in the Design Basis Documents and the stakeholder votes on the various iterations. Management informed the Board Markets Committee that it did not support the Design Basis Document that had been approved by NEPOOL, and proposed developing a new set of rules that, in management's estimation, would produce a more efficient market. The Board Markets Committee supported this proposal and encouraged management to continue working with stakeholders to determine if mutually-acceptable rules could be developed. The Committee noted that this topic would be discussed by the full Board and agreed that, given the importance of the issue, the Board should ultimately determine the ISO's position on the issue.

The Board Markets Committee reviewed its materials on PRD and discussed, in particular, the appropriate payment to resources in the supply-side program. That Committee

discussed the economics of paying the full locational marginal price (LMP) to supply-side PRD resources versus paying LMP less the applicable retail generation rate (G) (i.e., LMP or LMP-G). That Committee discussed also the Participants Committee votes and the positions of state regulators and various Sectors. The Board Markets Committee noted that this issue would be discussed in detail by the full Board and agreed that, given the importance of the issue, the ultimate position should be a Board decision.

Full Board

Mr. van Welie reported that the full Board of Directors met in Holyoke after the Board Markets Committee meeting. The Board approved the previously-mentioned amendments to the pension plans, supported the merit and promotional increases reflected in the 2010 budget recommended by the Compensation and Human Resources Committee, received Committee reports and discussed issues related to the potential jurisdiction of the Commodity Futures Trading Commission. The Board also authorized management to execute an operating agreement with the New England Independent Transmission Company, LLC. The primary focus of the remainder of the Board meeting was to review FCM and PRD issues.

Regarding FCM, the Board had received detailed briefing materials. The Board reviewed these materials and received a report from the Board Markets Committee on its discussion of this topic. That Board Markets Committee recommended that management develop its own rules for filing while simultaneously working with stakeholders to develop a set of rules that could receive NEPOOL support. The Board supported this proposal, which included the possibility of rules that include the reinstatement of a time limit on the carry-forward of out-of-market capacity and an extension of the price cap. However, the Board advised that, in the absence of NEPOOL and state regulator support, management should file the rules that it believed to be most efficient.

The Board then discussed the topic of supply-side PRD payments. After a review of the briefing materials, a report from the Board Markets Committee, and discussion with management, the Board authorized management to move forward with a supply-side PRD proposal based upon the payment to Participants of LMP-G. The Board concluded that the proposal to pay the full LMP would distort the market and create inefficient prices, and that there were other more appropriate means of reducing barriers to entry for demand resources.

Mr. van Welie went on to report that, following the Board meeting, the FERC issued an order on New England's compliance filing in response to Order No. 719. In that order, the FERC noted that progress has been made in New England regarding PRD and concluded that the June 1 filing on PRD was an appropriate time to address broader issues on that subject.

Reacting to that FERC order, Mr. van Welie said that current constraints on internal resources addressing demand resource integration and settlement in FCM, combined with the length of the stakeholder process on PRD thus far, would preclude the ISO from meeting that June schedule with a full set of rules on supply- and demand-side PRD programs. Additionally, he said that the region appeared to be irreconcilably divided on the appropriate payment methodology for PRD resources. The payment methodology and cost allocation were important cornerstones in much of the development work and would affect the details of system dispatch and settlements. As a result, ISO management proposed to work with NEPOOL and state regulators to split the PRD filing into two phases. In the first phase, targeted for April, the ISO would file a narrow set of rules that will address the payment methodology and cost allocation. Depending on NEPOOL's final vote, that filing would include rules reflecting the ISO's position of paying LMP-G and, if NEPOOL approves an alternative proposal, the filing would be a jump-ball filing that would also include the proposed rules approved by NEPOOL. He said the ISO

also would work with NECPUC, as it does with Participants, to assist in their development of rules that set forth their position, so that NEPOOL and FERC will have the full issues before them.

Following the CEO report, the members discussed the ISO's proposal on PRD. Some members questioned whether the region might be better served by a filing supporting the request by the Consumer Demand Response Initiative (CDRI) for a FERC order providing guidance on certain issues. The ISO made clear its position that the issues needed to be presented in the form of a specific proposed Market Rule change which it would file, hopefully with NEPOOL support, but with a NEPOOL alternative if that were the outcome. Other members urged that the phased filing not require an investment of resources that might be better spent within the stakeholder process addressing remaining issues. Still others questioned whether the issue of cost allocation, without FERC direction on payment issues, was ripe for FERC consideration, and encouraged the ISO to consider whether it would be more efficient to await further FERC guidance on payment issues before proceeding with a cost allocation proposal. It was also reported that the FERC had not yet acted on, and therefore no guidance could be gleaned from, the PJM demand response proceeding pending before the FERC in Docket No. EL09-68.

Mr. van Welie then asked Mr. Robert Ludlow to report on FERC's consideration of metrics for reporting on ISO and RTO performance. Mr. Ludlow reviewed materials on the topic that had been circulated in advance of the meeting. He also reported that a workshop would be held on the topic later in the month, that will be facilitated by Mr. Hans Mertens of the Vermont Department of Public Service for NECPUC and Mr. Paul Peterson for NEPOOL.

Finally, Mr. van Welie asked Mr. Raymond Hepper to report on the ISO's future plans with respect to future requests for waiver of the FCM pre-qualification Market Rules. Mr.

Hepper explained that the ISO intends to be less supportive of future waivers. The FCM Market Rules, he said, have now been out and implemented through several auctions and the ISO needs, in fairness to all, to expect future compliance with those Rules. A member urged the ISO to modify the Rules to remove inflexible provisions that produce the draconian result of excluding resources from an auction because of immaterial, ministerial deviations from expectations.

REPORT OF ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada then reviewed highlights from the monthly COO report, which was circulated in advance of the meeting and posted on the ISO website. He indicated that January natural gas prices were 8.9% higher and oil prices 2.7% higher than the December 2009 values. He reported that January Real-Time Hub LMPs were approximately 5% higher from December averages.

Turning to Net Commitment Period Compensation (NCPC), Dr. Chadalavada reported that NCPC payments for January totaled $4 million, which was a decrease of $2.5 million from December. He indicated that January First Contingency payments totaled $3.9 million: $3.8 million paid to internal resources and $107,000 paid to resources at external locations; with $2.8 million in payments during the first week in January. He noted that NPCP payments were 0.6% of the total Energy Market value during January.

Dr. Chadalavada reported that the next Planning Advisory Committee (PAC) meeting was scheduled for February 24 to review the 2010 load forecast, both region-wide and state-by-state, as well as an update on the Regional System Plan (RSP10) process. He reminded the Committee that the Economic Study Requests were due to be submitted by April 1. He reported that the ISO completed testifying in the proceedings relating to the Greater Springfield Reliability Project (GSRP). Parties are now awaiting a decision by the siting council's hearing

officer, and the ISO was hoping that the proceeding would come to a conclusion soon. He said that the experiences from the Massachusetts proceedings had been a good indicator for the sorts of analysis that ISO would need to prepare with respect to future transmission projects. A Massachusetts representative commended the ISO for its efforts in those proceedings.

Turning to the Winter/Spring Operable Capacity analysis, Dr. Chadalavada reported that the ISO forecasted the lowest Winter/Spring Operable Capacity Margin for the week beginning May 8, 2010, and that the projected operable capacity was adequate for both the reference load of 50/50 and the extreme load of 90/10.

Dr. Chadalavada noted that several slides in the report which identified new generation had not been updated, and that the next report would show results for both January and February.

He concluded his report by informing the Committee that the ISO would plan to be available following the conclusion of the meeting to review the details of the 2010/2011 work plan that included all of the initiatives expected to be worked on over the subsequent 18 months.

Several members then asked clarifying questions regarding the COO report. One member asked for further information concerning the increase in NCPC during late December and early January. Dr. Chadalavada explained in response that the size of the NCPC was influenced principally by forced outages and deviations between projected and actual load. He said that forced outages of the magnitude experienced in that time frame, exacerbated by colder weather and load forecasting challenges, were extremely difficult to predict accurately. The circumstances leading to the high NCPC during that time frame had since abated and the ISO had no ability to predict with any certainty when or if they would re-occur in the foreseeable future.

BILLING AND FINANCIAL ASSURANCE POLICIES CHANGES TO SUSPENSION AND PRE-PAYMENT PROVISIONS

Mr. Joel Gordon, Chair of the Budget & Finance Subcommittee, then referred the Committee to materials that were circulated in advance of the meeting regarding proposed changes to the suspension and pre-payment provisions of the Billing and Financial Assurance Policies. Noting that the two proposed changes were essentially clean-up and ministerial in nature, he explained that the first change aligned the prepayment provisions of the Policies with the timing of the issuance of Invoices, which had recently been moved to Monday or the first business day of the week. The second change, he explained, replaced the suspension provisions in the Billing Policy relating to payment defaults, with a reference to the parallel suspension provisions of the Financial Assurance Policy, which would simplify administration of the Policies going forward. Mr. Gordon reported that the ISO discussed the proposed changes with the Subcommittee during its January 11 teleconference, and that no Subcommittee members had objected to the changes.

The following motion was then duly made, seconded and unanimously approved:

> RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy circulated to the Committee and discussed at this meeting, together with such further non-substantive changes as the Chief Financial Officer of the ISO and the Chairman of the Budget & Finance Subcommittee may approve.

SUSPENSION OF SECONDARY FTR MARKET

Ms. Allison DiGrande, Chair of the NEPOOL Markets Committee, then reviewed materials that were circulated to the Committee in advance of the meeting regarding the unanimous recommendation of the Markets Committee for approval of the suspension of the

secondary market for Financial Transmission Rights (FTRs) and the removal of all provisions pertaining to that market until new systems implementing the FERC-approved Long-Term FTR (LFTR) rules were in place. She explained that the reason for suspending the thinly-traded market was to minimize the financial risk associated with leaving the market in place pending future implementation of the LFTR mechanisms.

Additionally, Ms. DiGrande explained that, following the Markets Committee's consideration and vote on the changes, additional references to the Secondary FTR Market were identified in Section I of the Tariff that should also be removed. She indicated that, absent objection, those changes would also be included for approval as part of the main motion. At Mr. Forshaw's request, NEPOOL Counsel confirmed that the changes were consistent with the intent of the Markets Committee recommendation and ministerial in nature. There was no objection to including the additional changes in the main motion.

The following motion was then duly made, seconded, and unanimously:

> RESOLVED, that the Participants Committee supports the revisions that suspend the Secondary FTR Market provisions until new systems implementing the FERC-approved Long Term Financial Transmission Rights rules are in place, as recommended by the Markets Committee and circulated to this Committee in advance of this meeting, together with the conforming changes to Section I of the Tariff, any other changes agreed to at this meeting, and such other non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

RESOURCES WITH COMMON COSTS THAT SEEK TO DE-LIST

Ms. DiGrande then referred to the Committee to materials circulated in advance of the meeting regarding changes to Market Rule 1 that address resources with common costs that seek to de-list. She explained that the changes were proposed in response to a FERC order directing the ISO to address common station costs shared among capacity resources and the recovery

thereof when de-list bids are rejected for reliability reasons. She stated that the proposal, originally developed by the Internal Market Monitor, was considered and supported by a 74.36% Vote in favor of by the Markets Committee at its January 26, 2010 meeting, with a number of abstentions noted.

At Mr. Forshaw's request, Mr. Marc Montalvo, on behalf of ISO, described additional revisions, circulated the evening before the meeting, that the ISO proposed be included with the changes under consideration. Mr. Montalvo explained that, during the ISO's final review, it became apparent that the proposed Market Rule language did not fully reflect the design that had been described to, and supported by, the Markets Committee. He stated that the additional changes clarified the proposed revisions, consistent with the intent of ensuring that resources that share common costs would be able to submit de-list bids that reflect economies of scale while other resources de-list out of the market, and would further the intent that resources retained for reliability receive just and reasonable compensation. He stated that such compensation should be the cost associated with the particular retained resource. Furthermore, he explained the ISO's view that any station common costs incurred should be recovered by the station as a whole. He stated that, absent the additional changes, the language voted by the Markets Committee would not sufficiently accomplish the latter part of the design intent. He stated that the revised language fully effectuated the intent and asked the Participants Committee to support the proposed changes with the additional revisions included.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 that address the treatment of Existing Generating Capacity Resources with common costs that seek to de-list, as recommended by the Markets Committee and circulated to this Committee in advance of this meeting, together with the

changes agreed to at this meeting and such other non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

A member commended the ISO for its development efforts and then opined that, when common costs are incurred at a station with multiple units, it was proper to allocate common costs to unit(s) at a station whose de-list bid(s) were rejected for reliability reasons while other units at the station remain in the market. The unit retained for reliability reasons, he suggested, should be paid under a reliability agreement its fair share of the common costs. The member declined, however, to take the Committee's time with an offer to amend the main motion to include such an understanding because the issue had been fully vetted, but not supported, during Markets Committee consideration of the matter.

Following further discussion, the Market Rules as recommended by the Markets Committee, together with the additional revisions described by Mr. Montalvo, were then voted by a show of hands and passed, with oppositions from Boston Gen, Exelon, and PSEG, and abstentions by BG Dighton, BP, Brookfield, Caithness, ConEd, CSC, Dominion, Dynegy, Entergy, GDF Suez, Granite Ridge, LIPA, Millennium, Mirant, NAEA, NextEra, NRG, Pepco, PPL, and the Small Renewable Generation Group.

COMPETITIVE OFFER REQUIREMENTS FOR EXTERNAL CAPACITY RESOURCES

Ms. DiGrande then referred the Committee to materials circulated in advance of the meeting related to changes intended to enhance the competitiveness of offers from external capacity resources in FCM. She reported that the Markets Committee, at its January 12-13, 2010 meeting, had discussed and voted to recommend Participants Committee support for the changes with a 86.51 % Vote in favor. She further reported that two amendments had been offered

unsuccessfully at the Markets Committee meeting, with the amendment offered by HQUS, who had requested the matter be removed from the Consent Agenda, achieving a 56.51% Vote in favor at the Markets Committee.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 that enhance the competitiveness of offers from external capacity resources effective June 1, 2010, as recommended by the Markets Committee and circulated to this Committee in advance of this meeting, together with such other non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The HQUS representative then reviewed an amendment proposed by HQUS, which was duly made and seconded, that would strike from the recommended changes, the reduction, beginning June 1, 2013, of the heat rate used in the determination of the daily offer threshold from 22,000 to 14,400 btu/kwh. He went on to explain the HQUS concerns with that proposed reduction and why the proposed amendment would better reflect the opportunity costs and value associated with a hydro power facility during the periods when it is likely to deliver energy. He urged support for the amendment and stated that he would work to ensure consistent evaluation of all resources.

On behalf of the ISO, Mr. Andy Gillespie stated that the ISO did not support the amendment. He explained the ISO's view that the use of the Forward Reserve Market (FRM) heat rate (14,400 btu/kwh) would be an appropriate upper boundary and would produce a dispatch rate of approximately 3%, consistent with the derivation of the FRM heat rate. He added that the 22,000 btu/kwh heat rate had been intended to be used only as a transition method.

The HQUS motion to amend the main motion was then voted and failed to pass with a 51% Vote in favor. (Generation – 17.3%; Transmission – 2.47%; Supplier- 11.98%; Alternative

Resources – 1.95%; Publicly Owned Entity – 17.3%; and End User – 0%). (See Vote 1 on Attachment 2).

The unamended main motion was then voted by a show of hands and passed with oppositions from Dynegy and PSEG, and abstentions by BP, Brookfield, Caithness, ConEd, Constellation, CSC, Dominion, EnerNOC, Entergy, GDF Suez, Generation Sector Provisional Member Group, HQUS, Granite Ridge, International Power, LIPA, Millennium, Mirant, NAEA, NextEra, NRG, PEPCO, and the Small Renewable Generation Group.

FCM REVISIONS TO MARKET RULE 1, SECTION 13

Ms. DiGrande then reviewed materials that were circulated to the Committee in advance of the meeting regarding rule changes to the FCM Market Rules. Ms. DiGrande explained that the Markets Committee, at its January 26, 2010 meeting, began its deliberations with the set of rule changes to Section 13 of Market Rule 1 that implemented the Design Basis Document that was supported by the Participants Committee at is November 6, 2009 meeting, but then considered and ultimately supported with a 86.15% Vote in favor an amendment offered by National Grid to remove and replace certain provisions relating to CONE, the price floor, MW pro-rationing, carried forward excess out-of-market capacity, and ISO requests for energy. Ms. DiGrande stated that the Markets Committee next considered, and did not support, several other amendments to Section 13 of Market Rule 1 offered by members of the Generation and Supplier Sectors. The amended motion was then considered and supported by the Markets Committee with a 71.69% Vote in favor.

Mr. Forshaw clarified for the Committee that it was being asked to provide input on two sets of FCM rule changes, one set that was recommended by the Markets Committee to Section 13, and one set that was recommended by the Reliability Committee to Section 12. Mr. Forshaw

stated that the Committee would proceed first through all of the Section 13 changes and, when completed, would then address the Section 12 changes.

The following main motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Section 13 of Market Rule 1 and related definitions relating to the Forward Capacity Market as recommended by the Markets Committee, as supported by the ISO, and as circulated to this Committee in advance of this meeting, together with such other non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Mr. Michael Harrington, of the New Hampshire Public Utilities Commission, stated that NECPUC supported the main motion, and, as it had at the Markets Committee, encouraged support for the package of revisions. Mr. Thomas Kaslow, on behalf of GDF Suez, then offered a motion to amend the main motion to permit generating and import capacity resources to sell capacity under the same terms as Real-Time Demand Response Resources and Real-time Emergency Generation and in so doing, to accept the same sets of obligations and participation in the markets should they clear under those conditions.

The motion to amend the main motion as proposed by GDF Suez was then voted and failed with a 27.90% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 8.65%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 0%). (See Vote 2 on Attachment 2).

The Mirant representative next offered a motion to amend the main motion to revise certain language addressing the review by the Internal Market Monitor of offers from new generating capacity and demand resources below 0.75 times CONE. He stated that the Design Basis Document that came out of the FCM Working Group (FCMWG) process clearly indicated that expected net revenues excluded revenues that were only for new resources but not existing

and further that the proposed tariff language did not specifically capture that agreement and he had concerns that the intent could be lost over time. He next clarified that in order to accommodate concerns expressed by the Markets Committee that "or its vintage" could be interpreted to apply to the reference regarding economic development incentives, he had revised his amendment by adding a period after the phrase "or its vintage" and inserting the phrase "provided, however" at the start of a new sentence regarding economic development incentives. Finally, noted also Mirant's proposal struck the word "expressly" from the language out of an interest not to handcuff the ISO with the use of that term. He explained this proposal was slightly different from the request at the Markets Committee, reflecting additional discussions with Market Participants in the interim.

Mr. Doot requested that the ISO confirm whether it remained opposed to this amendment, given the changes from the versions presented to the Markets Committee. The ISO confirmed its continued opposition. State regulators, as well, confirmed their opposition to this amendment. At the request of Participants, Mr. Montalvo explained further the ISO's opposition. He explained a couple of general concerns with the proposed language recommended by Mirant, none of which, he indicated, had changed as a result of Mirant's proposed revisions, stating first that there may be situations where contractual arrangements sought by parties for capacity in which the evaluation of new versus existing or other parameter was part of the selection decision, and that may be more broad than the particular instance of economic development. As such, the ISO did not want to expressly exclude that from consideration. Mr. Montalvo then stated that the ISO supported the inclusion of the term "expressly" in the proposed language given that, absent any written document, the ISO would

have to infer what was intended and that would not be sufficient to reject offers under this Tariff provision.

The motion to amend the main motion as proposed by Mirant was then voted and failed with a 36.55% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 17.3%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 0%). (See Vote 3 on Attachment 2).

The NRG representative next offered a motion to amend the main motion, which he stated was the same motion offered at the Markets Committee, that would allow all static, export, administrative export, and permanent de-list bids that have been reviewed and approved by the Internal Market Monitor and FERC under the current mitigation rules to be eligible to set the price in Capacity Zones. He explained that this was a fairly complex issue and he had not drafted language, but rather would be seeking support from the Committee for direction to the ISO and stakeholders to prepare Market Rule language that would implement the understanding in time for the fifth Forward Capacity Auction (FCA5).

A member of the End User Sector expressed his support for this motion to amend, explaining that it raises an important issue worth evaluating that could have a significant impact on prices in the region and could mask inefficiencies that the market was set up to address. The NGrid representative spoke in opposition to the motion to amend, stating that the region had already spent a considerable time evaluating how de-list bids should affect price and that to go any further than the proposed rules would require a full evaluation of the current market design.

After further discussion, the motion to amend the main motion as proposed by NRG was then seconded, voted and failed with a 41.74% Vote in favor (Generation – 17.3%; Transmission

– 0%; Supplier 17.3%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 5.19%). (See Vote 4 on Attachment 2).

Next, the PSEG representative offered a motion to amend the main motion to revise the definition of FCM Pivotal Supplier. He explained that this amendment was slightly different than the one presented to the Markets Committee. He stated that, under this amendment, which had been circulated in advance of the meeting, there would be certain exemptions from the definition of FCM Pivotal Suppliers under two circumstances, one in which the resource owner seeks to de-list all of its capacity in a particular capacity zone and the second where the resource owner has less then five percent of the total capacity in that zone. The PSEG representative explained that, without these exemptions, there could be circumstances that would produce undesirable consequences. For example, he stated that if the capacity zone were modeled such that there was only 1 MW of shortage in that zone, every resource that was greater than 1 MW would be ineligible to set the price in that zone and there could be multiple resources in that area that could fit in that category. Second, he stated that there could be a situation where there would be 100 MW needed for reliability (and units are unable to de-list as a result) but the capacity zone would not be modeled because none of the resources in the zone were able to set the price. He stated that PSEG's proposed amendment would help to remedy such circumstances.

Mr. Doot asked for confirmation of the ISO and state regulator's positions on this amendment given the changes following the Markets Committee's consideration. Mr. Montalvo stated that the ISO opposed this amendment on the basis that they had not had a chance to fully examine its impacts. Mr. Harrington indicated that the state regulators were not in support of this amendment. The PSEG member expressed surprise that the ISO had not yet reviewed the

impact of this proposed amendment, since it was first offered at the FCM Working Group last summer and at several Markets Committee meetings since then.

The motion to amend the main motion as proposed by PSEG was then voted and failed with a 36.55% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 17.3%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 5.19%). (See Vote 5 on Attachment 2).

The PSEG member then offered a second motion to amend the main motion regarding ISO requests for energy from resources that do not have a Capacity Supply Obligation (CSO). He explained that this proposed amendment would treat resources that do not have a CSO similar to the manner in which external resources are treated under the rules governing Emergency Energy Transactions (EETs). Under those rules, if the ISO concluded it had a need for emergency energy, it would issue a request for EETs and invite all external resources that do not have a CSO to respond. He stated that the current rules only permit external resources to participate and that PSEG's second proposed amendment would open the door for internal generation to compete on the same footing as external generation. The PSEG representative further explained that there would be uplift payments given that EETs would not be eligible to set price, but that there would be greater competition among EETs overall.

Support was expressed for further evaluation of whether the region should expand eligibility for EETs, with some noting beliefs that the reason for such restriction today may be a result of how external resources are scheduled as compared to internal generation. Mr. Doot confirmed that this amendment was the same as that which was presented to the Markets Committee.

The motion to amend the main motion as proposed by PSEG was then voted and failed with a 29.74% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 10.49%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 5.19%). (See Vote 6 on Attachment 2).

The representative of GDF Suez next offered a motion to amend the main motion to revise the language regarding ISO requests for energy. This member noted that he has revised his amendment from the version that had been circulated in advance to this Committee in order to remove from consideration (1) the insertion "after activation of all capacity subject to a Capacity Supply Obligation" and (2) the two phrases from Section III.13.6.4 inserted by the Markets Committee that stated "under Section III.13 of this Tariff by such a request." The effect of this motion to amend essentially would be to restore the language in these respects back to what is now in the present Market Rules (with the exception of the added phrase "that is not subject to a Capacity Supply Obligation").

Mr. Doot asked the ISO and state regulators whether this change would have any impact on their positions with respect to this amendment. Both the ISO and state regulators indicated they remained opposed to this amendment. ~~In response to a question from the sponsor, Mr. Robert Ethier indicated that~~The sponsor asked the ISO if they believed there are ~~no~~any obligations imposed on resources without a CSO outside of Section 13 of Market Rule 1 ~~on resources without a CSO~~ that would obligate those resources. Mr. Robert Ethier stated no and further explained that ISO includes this language in the Market Rule to clarify that when interpreting and implementing Section 13, references in Section 13.6.4 are referring only to Section 13 obligations.

The motion to amend the main motion as proposed by GDF Suez was then voted and failed with a 36.55% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 17.3%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 5.19%). (See Vote 7 on Attachment 2).

Mr. Harrington requested that the minutes of this Committee reflect the commitment made by the ISO that they would keep track of all generating resources that do not have a CSO that participate in the energy market and collect that information for two years and going forward in the future to see if we can draw any conclusions about their reliability. Mr. Mark Karl, on behalf of the ISO, concurred with that commitment and stated that the ISO will accumulate that data for all time periods, not just during emergency periods, and will come back at least within two years to discuss with stakeholders what conclusions can be drawn from those results.

Following these series of failed motions to amend, representatives of companies with supply resources in the region expressed their concerns with the resulting Market Rule changes. One member expressed appreciation for the time and effort involved in identifying these reforms, but expressed the view that the region has lost an opportunity to make meaningful reforms. Others also echoed that sentiment, expressing appreciation for the work done especially by the load parties during the effort, but noting that the market would be doomed to fail unless the region addresses the issues regarding out-of-market resources. The member representing the CT OCC and NH OCA, noted that both offices support the Rule changes but would be abstaining at this meeting due to concerns regarding the extension of the carried forward OOM capacity from 5 to 7 years. On behalf of NECPUC, Mr. Harrington sought and received assurances from ISO that it would include negotiated language with the State of Maine in the filing letter to address future review of these Market Rules. Mr. Ethier explained that the negotiated language included

a commitment to look at the definitions of out-of-market capacity and the functioning of the APR rules as well as the hiring of an economic consultant. In response to a further inquiry, Mr. Karl also confirmed that the filing letter would include language similar to the commitment made in the Design Basis Document addressing enhancements to the Regional System Planning process.

The unamended main motion was then voted and passed with a 70.10% Vote in favor (Generation – 0%; Transmission – 17.3%; Supplier – 6.65%; Alternative Resources – 11.55%; Publicly Owned Entity – 17.3%; and End User – 17.3%). (See Vote 8 on Attachment 2).

FCM REVISIONS TO MARKET RULE 1, SECTION 12

Mr. Donald Gates, Chair of the NEPOOL Reliability Committee, then reviewed materials that were circulated to the Committee in advance of the meeting regarding Rule changes to Section 12 pertaining to the Forward Capacity Market. Similar to the Markets Committee, Mr. Gates stated that the Reliability Committee at its January 28, 2010 meeting began its deliberations with the set of rule changes to Section 12 of Market Rule 1 that implemented the Design Basis Document that was supported by the Participants Committee at its November 6, 2009 meeting. The Reliability Committee then considered and ultimately supported with a vote reflecting no opposition and eleven abstentions an amendment offered by NGrid to remove certain provisions in that section. Mr. Gates reported also that the Reliability Committee considered, and did not support, two proposed amendments to Section 12 of Market Rule 1, one offered by NRG and another by GDF Suez. Mr. Gates stated that the Reliability Committee recommended Participants Committee support for the Section 12 changes by a 65.4% Vote in favor.

The following main motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Section 12 of Market Rule 1 relating to the Forward Capacity Market as recommended by the Reliability Committee, as supported by the ISO, and as circulated to this Committee in advance of this meeting, together with such other non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

Mr. Harrington reported that this motion is supported by NECPUC and urged the Committee to approve it.

The NRG member offered a motion to amend the main motion to provide that, using the ISO's methodology and where such zones can be modeled, all capacity zones should be modeled at all times. He stated that this was the same amendment that was offered at the Reliability Committee. He explained that the issue of when zones are modeled is not a reliability issue, but rather is a markets issue, and as described in NRG's amendment presented to the Markets Committee, there are comprehensive mitigation rules in place to ensure there are no market power issues once you do model zones. The NGrid representative noted that NGrid had the same concerns with this amendment as it did with the NRG's proposed amendment to Section 13 that had been proposed at the Markets Committee.

The motion to amend the main motion as proposed by NRG was then voted and failed with a 36.55% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 17.3%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 5.19%). (See Vote 9 on Attachment 2).

The GDF Suez member next offered a motion to amend the main motion to ensure that the Local Sourcing Requirement (LSR) or the capacity requirement for the Rest of System is not understated in situations where a valid Transmission Security Analysis (TSA) may exist for the Rest of System zone. He explained that the Market Rule changes recommended by the

Reliability Committee would change the calculation of the Maximum Capacity Limit (MCL). He said that the existing Rules currently define the MCL as the ICR less the LSR and the changes recommended by the Reliability Committee would amend that to be the ICR less the Local Resource Adequacy requirement. He explained that GDF Suez's proposed amendment was intended to maintain the definition of MCL as the ICR less the LSR, but to add a new section dealing with LSR that would state that in the event there is no valid TSA for the Rest of System zone, one cannot be used in the calculation of LSR for the Rest of System. He explained that this amendment was intended to maintain the existing symmetry between the MCL and the LSR calculations and to ensure that there is no understatement of the capacity requirement for the Rest of System.

Mr. Karl indicated that the ISO opposed this amendment. The ISO had reviewed the issue presented but was unsure of what criteria would apply in order to calculate a TSA for an unconstrained zone. Further, the ISO was concerned that the amendment if passed would negatively impact auction design. The sponsor of this motion to amend responded with his view that concerns regarding impacts on the auction should not be a reason not to evaluate this issue.

After further discussion, the motion to amend the main motion as proposed by GDF Suez was then voted and failed with a 33.8% Vote in favor (Generation – 17.3%; Transmission – 0%; Supplier 14.55%; Alternative Resources – 1.95%; Publicly Owned Entity – 0%; and End User – 0%). (See Vote 10 on Attachment 2).

The unamended main motion was then voted and passed with a 71.69% Vote in favor (Generation – 0%; Transmission – 17.3%; Supplier – 6.29%; Alternative Resources – 13.5%; Publicly Owned Entity – 17.3%; and End User – 17.3%). (See Vote 11 on Attachment 2).

ISO PROPOSAL REGARDING SCHEDULE FOR RESOLUTION OF TIE BENEFITS ISSUES

Addressing a matter that, during the January Participants Committee meeting had been sent to the Reliability Committee for a recommendation, Mr. Gates reported on the Reliability Committee's action regarding the ISO's process proposal for addressing tie benefit issues. He reminded the Committee that the ISO proposed to comprehensively review and attempt to resolve all outstanding and identified tie benefits issues through a NEPOOL stakeholder process in the appropriate NEPOOL committees during 2010 and to make a filing with the FERC on or before a date that would allow any related Rule or Tariff changes to be effective in time for FCA5. He indicated that the Reliability Committee discussed and voted the proposal at its January 20, 2010 meeting, but that there was not sufficient support on any proposed response to the ISO request in order to present a recommendation to the Participants Committee. He mentioned that Cross Sound Cable and LIPA offered an amendment that would have carved out one of the so-called "Reserved Issues", but that, too, was not supported.

In the absence of a formal recommendation, Mr. Forshaw asked whether any Participant wished to move the motion that was considered by the Reliability Committee at its January 20 meeting. The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the ISO's proposal to comprehensively review and attempt to resolve all outstanding and identified tie benefits issues (including, without limitation, the so-called "Reserved Issues" specified in Docket No. ER08-41) through a NEPOOL stakeholder process in the appropriate NEPOOL committees during 2010 and to make a filing with the Federal Energy Regulatory Commission on or before a date that will allow any related Rule or Tariff changes to be effective in time for the fifth Forward Capacity Auction covering the 2014-2015 Capacity Commitment Period.

The LIPA representative raised a concern that the Reserved Issues were again being deferred. He reminded the Committee that, in November 2008, the Participants Committee had considered

the three issues referred to as the "Reserved Issues" and agreed to a process to address them by February 2010. He stated that, at that time, LIPA was opposed to the resolution because of its view that the issues should be addressed prior to February 2010. He reminded the Committee of its support for that resolution and the subsequent inclusion of that agreement in a FERC filing. He noted that the ISO's latest proposal, yet again, extended the time for addressing the Reserved Issues. The LIPA representative also stated that Power Supply Planning Committee (PSPC) had done a lot of work on the issues and seemed to be ready to make a recommendation on how to proceed. He noted LIPA's objection to rolling the Reserved Issues into the larger tie benefits project, noted LIPA's opposition to the proposal before the Committee, and urged others to vote against the proposal as well. Several other members raised similar process concerns and the ISO's delay in addressing issues that Participants had legitimately raised. The CSC representative reiterated LIPA's concerns and urged members to vote against the ISO proposal because of the process; he stated that, regardless of position on the substance of the Reserved Issues, the ISO proposal should not be supported because of how the issue had evolved to date. Those opposing the motion urged the Committee not to validate ISO's process in terms of not addressing this issue and meeting its commitment to do so by February 2010. He urged members to consider how they would respond if they were treated similar to CSC and LIPA on an issue important to them.

An AR Sector representative stated that some of his clients would vote against the ISO proposal based on the process concerns raised by CSC and LIPA. He added, though, that several of those clients would prefer to have the commencement of the tie benefits issues stakeholder process put off until the last quarter of 2010 so that they could deal with the issues associated with the implementation of FCM.

Other members spoke up in support of the resolution, one member noting that the ISO had already made its filing at the FERC, and that Participants should not oppose a proposal that reflects pragmatically the ISO's conclusion as to how to advance multiple objectives. The MA AG expressed support for the ISO proposal on a contingent basis, stating that the ISO should come up with a timeline for action on the various pieces of the ICR tie benefits issues.

One member stated that the Participants he represented could otherwise support the suggestion to address all these issues together and comprehensively in 2010, but would be opposing the resolution here because the ISO failed to provide timely notice of its plans and to consult with NEPOOL before committing to a schedule change.

Mr. Karl noted that the Participants were being asked only to vote on their position with respect to ISO's FERC filing and explained why the ISO had decided to consolidate all the tie benefits issues and that the ISO has a large list of such issues to address. He said that the Reliability Committee had assembled a working document on these issues in its discussions of FCM, even before the creation of the FCMWG. Indeed, he noted that the FCMWG was formed partly in response to the prior commitment that was made to deal with the zonal requirements issue. He explained that the FCMWG ended up absorbing the attention and resources of the ISO and Participants, preventing the ISO from fully addressing sooner the tie benefits issues. The comprehensive list of tie benefits issues demonstrates that the volume of work overwhelms the available resources of ISO and the Participants and a more realistic and holistic work plan and schedule was needed. Mr. Karl concluded his remarks by indicating that discussions at the Reliability Committee would be held on the work plan to see if a schedule could be created that works for everyone and completes the task in time for FCA5.

Focusing on the resolution before the Committee, some members expressed further concerns regarding the process. While they were supportive generally of dealing with all these issues comprehensively, they were concerned about trying to complete the task by year-end given other time commitments and priorities. In response to further questions, Mr. Doot explained that the issue for the Committee was whether it wished in the circumstances to support the ISO's proposal to complete a comprehensive review by year end. Embedded in that question are the questions of (1) Does the Committee support the timeframe that the ISO has identified, and (2) What message does the Committee wish send to FERC in the ongoing proceeding. Mr. Doot then summarized what he would expect the filing to include depending on the outcome of the vote.

After further discussion, the motion was then voted and failed with a 43.25 % Vote in favor and abstentions noted (Generation – 0%; Transmission – 17.3%; Supplier – 0%; Alternative Resources – 0 %; Publicly Owned Entity – 17.3%; and End User – 8.65 %). (See Vote 12 on Attachment 2).

CONFORMING CHANGE TO MARKET RULE 1, SECTION 12.6 (RETIREMENT OF CAPACITY RESOURCES UNDER FCM)

Mr. Gates referred the Committee to materials circulated in advance of the meeting regarding an amendment to Market Rule 1, Section 12.6 that had been unanimously recommended by the Reliability Committee. He explained that the amendment would conform that section of Market Rule 1 to changes made earlier to the Tariff that subject the retirement of certain capacity resources to provisions of the Market Rules rather than Section I.3.9 of the Tariff. But for the timing of the Reliability Committee action, he explained, the item would have been on the Consent Agenda.

Without further discussion, the following motion was duly made, seconded and unanimously approved:

> RESOLVED, that the Participants Committee supports the amendment to Section 12.6 of Market Rule 1, as recommended by the Reliability Committee at its January 28, 2010 meeting, together with such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

REVISIONS TO PP-10 (ADDRESSING OVERLAPPING IMPACT ANALYSIS TO BE APPLIED TO DEMAND RESOURCES PARTICIPATING IN FCM)

Mr. Gates then referred the Committee to materials circulated in advance of the meeting regarding revisions to Planning Procedure No. 10 (PP-10). He explained that the revisions addressed the overlapping impact analysis that would be applied to demand resources participating in FCM and were unanimously recommended by the Reliability Committee. Additionally, he noted that the ISO had committed to consider further enhancements to PP-10 to address certain aspects raised during the Reliability Committee's consideration of the changes.

Without further discussion, the Committee unanimously approved the following motion, with abstentions by NextEra, NRG, and PPL:

> RESOLVED, that the Participants Committee supports the revisions to PP-10, as recommended by the Reliability Committee at its January 28, 2010 meeting, together with such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report and to materials summarizing three general proceedings initiated by the FERC that had been circulated in advance of the meeting. He indicated that NEPOOL needed to decide whether, and to what extent, it wished to submit comments in the FERC proceedings– a Notice of Proposed Rulemaking (NOPR) on Credit Reforms (Credit Reform NOPR), and Notice of Inquiries (NOIs) regarding the integration

of Variable Energy Resources (VER NOI) and Electricity Market Transparency (EQR NOI) – each. To that end, he reported that the Credit Reform NOPR would be considered by the Budget & Finance Subcommittee; the VER NOI, by a working group to be chaired by Mr. Calvin Bowie; and the EQR NOI, by the Markets Committee. Notice of those discussions would be circulated in due course and Mr. Doot noted that members would be advised of any plans to comment following those discussions and further discussions with the NEPOOL Officers. Similarly, as reported earlier in the meeting, the FERC's proposed RTO/ISO metrics would be considered at a workshop to be scheduled the following week, with any decision on whether and to what extent NEPOOL comments might be appropriate or desirable to be determined following the workshop.

A member requested that ISO participate actively in those efforts and, where appropriate, summarize what, and to what extent, existing New England arrangements might be impacted by, or relevant or responsive to the FERC's initiatives.

COMMITTEE REPORTS

On behalf of the Joint Nominating Committee, Mr. Forshaw reported that a search firm had been retained to assist the Committee with the identification of potential Board candidates. He indicated that the Committee hoped to present a slate for Participants Committee approval either at the April or May 2010 meeting, with the ISO Board scheduled to act on the final slate of candidates at its September 2010 meeting.

OTHER BUSINESS

Mr. Doot then discussed the calendar for the remainder of February and March that had been circulated in advance of the meeting. He noted the next Participants Committee meeting

was scheduled for March 5 at the Seaport Hotel in Boston. He highlighted the NARUC Winter Committee Meetings that were to take place in Washington later that month. Mr. Doot also noted, as reported in the litigation report, a March 3 FERC technical conference on market-based rate and electric quarterly report filings.

There being no further business, the meeting was adjourned at 2:25 p.m.

Respectfully submitted,

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David T. Doot, Secretary

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ATTACHMENT 1

MEMBERS AND ALTERNATES ATTENDING
FEBRUARY 5, 2010 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
511 Plaza LP	End User	William P. Short III	Gus Fromuth	
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Bangor Hydro-Electric Company	Transmission		Stacy Dimou	
BG Dighton Power, LLC	Generation		William Fowler	
Boston Generating, LLC	Generation		William Fowler	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned		John Coyle (tel)	
Brookfield Energy Marketing /Cross-Sound Cable (CSC)	Supplier	Nicolas Bosse		Jose Rotger
Caithness New England Services Company	Generation		Ken Bekman	
Central Maine Power Company	Transmission			Sue Clary (tel)
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Comverge, Inc.	AR	Brad Swalwell (tel)		
Concord Municipal Light Plant	Publicly Owned		Gary Will	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Richard Steeves	Paul Peterson
Conservation Law Foundation	End User			Cindy Arcate
Conservation Services Group (CSG)	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier		Ken Bekman	
Constellation Energy Commodities Group, Inc.	Supplier	Dan Allegretti (tel)		
Corinth Wood Pellets LLC	End User		Gus Fromuth	
CPower, Inc.	AR	Janette Dudley (tel)		
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Dennis Beverage	End User	Gus Fromuth		
Dominion Energy Marketing, Inc.	Generation	Ron Hart (tel)		
Dragon Products Company LLC	End User	Gus Fromuth		
Dynegy/Calpine	Supplier	Glenn Haake		
Edison Mission Marketing and Trading	Supplier	Raymond Stalter (tel)		
Elektrisola, Inc.	End User		Gus Fromuth	
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy (tel)		
Entergy Nuclear Power Marketing, Inc.	Generation	Ronald Mackowiak (tel)		William Fowler
Exelon Generation Company, LLC	Supplier	William Fowler		
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
Food City, Inc.	End User	Gus Fromuth		
Garland Manufacturing Company	End User	Gus Fromuth		
Gas Recovery Systems, LLC (GRS)	AR		Doug Hurley	
GDF SUEZ Energy Marketing NA/FirstLight	Supplier		Thomas Kaslow	
Granite Ridge/Merrill Lynch/BOA	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault (tel)	Robert Stein	
Hammond Lumber Company	End User	Gus Fromuth		
Hardwood Products Company	End User		Gus Fromuth	
Harvard Dedicated Energy Limited	End User			Roger Borghesani
Hess Corporation	Supplier			Nancy Chafetz
Hingham Municipal Lighting Plant	Publicly Owned		John Coyle (tel)	

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MEMBERS AND ALTERNATES ATTENDING
FEBRUARY 5, 2010 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald Sipe		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
International Power America (ANP Funding I)	Generation	Dorothy Capra		
LaBree's Inc.	End User		Gus Fromuth	
Lavalley Lumber Co.	End User	Gus Fromuth		
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieney	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Skiing, Inc.	End User	Donald Sipe		
Maine Woods Pallet Company	End User	Gus Fromuth		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden's Inc.	End User	Gus Fromuth		
Massachusetts Attorney General's Office	End User	Jesse S. Reyes	David Cetola	
Massachusetts Municipal Wholesale Electric Co.	Publicly Owned	Gary Will		
Mead Oxford	End User	Donald Sipe		
Merchants Plaza, LLC	End User	Gus Fromuth		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
Millennium Power Partners	Generation		Ken Dell Orto	
Mirant Energy Trading, LLC	Generation	Phil Smith		
NAEA Energy Massachusetts, LLC	Generation	Ken Bekman		
New England Power Company	Transmission	Timothy Brennan		
New Hampshire Office of Consumer Advocate	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Fernando DaSilva		
Northeast Utilities Service Company (NU)	Transmission	Joseph Staszowski	Cal Bowie	
NRG Power Marketing, Inc.	Generation	Pete Fuller		
NSTAR Electric Company	Transmission	James Daly		
PalletOne of Maine	End User	Gus Fromuth		
Pascoag Utility District	Publicly Owned		John Coyle (tel)	
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
Pepco Energy Services, Inc.	Supplier			Nancy Chafetz
Pinpoint Power LLC	Supplier			Bob Stein
PowerOptions, Inc.	End User	Cindy Arcate		
PPL EnergyPlus	Supplier		Sharon Weber (tel)	Michelle Graening (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member – Generation Sector	Generation	Ken Dell Orto		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Quality Egg of New England, LLC	End User	Gus Fromuth		
RJF-Morin Brick	End User	Gus Fromuth		
Robbins Lumber, Inc.	End User	Gus Fromuth		

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MEMBERS AND ALTERNATES ATTENDING
FEBRUARY 5, 2010 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR			Doug Hurley
South Hadley Electric Light Department	Publicly Owned		Gary Will	
St. Anselm College	End User	Gus Fromuth		
St. Joseph Health Services of Rhode Island	End User	Gus Fromuth		
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Light Department	Publicly Owned		Brian Forshaw	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium (TEC)	End User	Roger Borghesani		
The Energy Council of RI (TEC-RI)	End User			Roger Borghesani
TransCanada Power Marketing Ltd.	Generation		Michael Hachey	
Union of Concerned Scientists (UCS)	End User		Paul Peterson	
United Illuminating Company, The	Transmission	Rich Peters		
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission		Kirk Shields (tel)	
Vermont Energy Investment Corporation (VEIC)	AR		Doug Hurley	
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westfield Gas & Electric Department	Publicly Owned	Anthony Contrino	Gerald Tomasko	Gary Will
Westerly Hospital	End User	Gus Fromuth		
Whole Foods Market Group, Inc.	End User	Gus Fromuth		
ZTECH, LLC	End User	Gus Fromuth		

Circulated 2/26/10; Marked Against 2/22/10 Draft
ATTACHMENT 2

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR	VOTE 1	VOTE 2	VOTE 3	VOTE 4	VOTE 5	VOTE 6	VOTE 7	VOTE 8	VOTE 9	VOTE 10	VOTE 11	VOTE 12
GENERATION	17.30	17.30	17.30	17.30	17.30	17.30	17.30	0.00	17.30	17.30	0.00	0.00
TRANSMISSION	2.47	0.00	0.00	0.00	0.00	0.00	0.00	17.30	0.00	0.00	17.30	17.30
SUPPLIER	11.98	8.65	17.30	17.30	17.30	10.49	17.30	6.65	17.30	14.55	6.29	0.00
ALTERNATIVE RESOURCES	1.95	1.95	1.95	1.95	1.95	1.95	1.95	11.55	1.95	1.95	13.50	0.00
PUBLICLY OWNED ENTITY	17.30	0.00	0.00	0.00	0.00	0.00	0.00	17.30	0.00	0.00	17.30	17.30
END USER	0.00	0.00	0.00	5.19	0.00	0.00	0.00	17.30	0.00	0.00	17.30	8.65
% IN FAVOR	51.00	27.90	36.55	41.74	36.55	29.74	36.55	70.10	36.55	33.80	71.69	43.25

Vote 1: HQ US Amendment (Competitive Offer Requirement for External Capacity Resources)

Vote 2: GDF Suez Amendment No. 1 Regarding Generation and Import Capacity Participation

Vote 3: Mirant Amendments (INTMMU Review of New Offers Below 0.75 times CONE)

Vote 4: NRG Amendment Regarding De-List Bids and Price Setting in Capacity Zones

Vote 5: PSEG Amendment No. 1 (Pivotal Supplier Definition)

Vote 6: PSEG Amendment No. 2 (ISO Requests for Energy

Vote 7: GDF Suez Amendment No. 1 (ISO Requests for Energy)

Vote 8: Main Motion (FCM Revisions to Market Rule 1, Section 13)

Vote 9: NRG Amendment Regarding Capacity Zones

Vote 10: GDF Suez Amendment Regarding TSA Requirements

Vote 11: Main Motion (FCM Revisions to Market Rule 1, Section 12)

Vote 12: ISO Proposal Regarding Schedule for Resolution of Tie Benefits Issues

Circulated 2/26/10; Marked Against 2/22/10 Draft
ATTACHMENT 2

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

GENERATION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
BG Dighton Power	A	F	F	F	F	F	F	O	F	F	A	O
Boston Generating	F	F	F	F	F	F	F	O	F	F	A	O
Caithness New England	F	F	F	F	F	F	F	O	F	F	O	A
Dominion Energy Marketing	F	F	F	F	F	F	F	O	F	F	O	O
Entergy Nuclear Power	A	F	F	F	F	F	F	O	F	F	O	A
International Power America	A	F	F	F	F	F	F	O	F	F	O	A
Millennium Power Partners	A	F	F	F	F	F	F	O	F	F	O	O
Mirant Energy Trading	A	F	F	F	F	F	F	O	F	F	O	O
NAEA Energy of Massachusetts	F	F	F	F	F	F	F	O	F	F	O	A
NextEra Energy Resources	--	F	F	F	F	F	F	O	F	F	O	A
NRG Power Marketing	F	F	F	F	F	F	F	O	F	F	O	A
TransCanada Power Marketing	A	F	F	F	F	F	F	O	F	F	O	A
Provisional Member Group	A	F	F	F	F	F	F	O	F	F	O	O
IN FAVOR (F)	5	12	12	12	12	12	12	0	12	12	0	0
OPPOSED (O)	0	0	0	0	0	0	0	12	0	0	10	5
TOTAL VOTES	5	12	12	12	12	12	12	12	12	12	10	5
ABSTENTIONS (A)	6	0	0	0	0	0	0	0	0	0	2	7

TRANSMISSION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
Bangor Hydro-Electric Co.	O	O	O	O	O	O	O	F	A	O	F	F
Central Maine Power Co.	O	O	O	O	O	O	O	F	O	O	F	F
New England Power Co.	O	O	O	O	O	O	O	F	O	O	F	F
Northeast Utilities System Co.	O	O	O	O	O	O	O	F	O	O	F	F
NSTAR Electric Co.	O	O	O	O	O	O	O	F	O	O	F	F
United Illuminating Co.	O	O	O	O	O	O	O	F	O	O	F	F
Vermont Electric Power Co.	F	O	O	O	O	O	O	F	O	O	F	F
IN FAVOR (F)	1	0	0	0	0	0	0	7	0	0	7	7
OPPOSED (O)	6	7	7	7	7	7	7	0	6	7	0	0
TOTAL VOTES	7	7	7	7	7	7	7	7	6	7	7	7

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

ABSTENTIONS (A)	0	0	0	0	0	0	0	0	1	0	0	0

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

SUPPLIER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
BP Energy Co.	A	A	A	A	A	O	A	A	A	A	A	A
Brookfield / CSC[1]												
Brookfield Energy Marketing	F	A	F	A	F	F	F	O	A	O	O	O
Cross-Sound Cable Company	F	A	A	A	A	A	F	O	A	A	O	O
Consolidated Edison Energy	A	A	A	F	A	A	F	A	F	F	O	O
Constellation Energy Commodities Grp	F	O	A	A	A	A	A	F	F	F	O	A
DC Energy	A	A	A	A	A	A	A	A	--	--	--	A
Dynegy/Calpine	F	F	F	F	F	F	F	O	--	O	O	A
Energy America	O	O	A	F	A	O	F	F	F	F	F	A
Exelon Generation	F	A	F	F	F	F	F	O	F	F	A	O
GDF SUEZ / FirstLight	F	F	F	F	F	F	F	O	F	F	O	A
Granite Ridge / Merrill Lynch / BoA	A	F	F	F	F	F	F	O	F	F	A	O
H.Q. Energy Services (U.S.)	F	A	F	F	F	F	F	A	F	F	A	O
Hess Corporation	O	O	A	F	A	O	F	F	F	A	F	A
Integrys Energy Services	O	O	A	F	A	O	F	F	F	A	F	A
LIPA	F	F	A	A	A	A	A	O	A	A	O	O
Pepco Energy Services	O	O	A	A	A	O	F	F	A	A	F	A
Pinpoint Power	F	A	A	F	A	A	A	A	F	F	A	O
PPL EnergyPlus	A	A	F	F	F	F	F	O	--	--	A	A
PSEG Energy Resources & Trade	F	F	F	F	F	F	F	O	F	F	O	A
IN FAVOR (F)	9.0	5.0	7.7	12.0	7.7	7.7	13.0	5.0	11.0	9.0	4.0	0.0
OPPOSED (O)	4.0	5.0	0.0	0.0	0.0	5.0	0.0	8.0	0.0	1.7	7.0	7.0
TOTAL VOTES	13.0	10.0	7.7	12.0	7.7	12.7	13.0	13.0	11.0	10.7	11.0	7.0
ABSTENTIONS (A)	5.0	8.0	10.3	6.0	10.3	5.3	5.0	5.0	4.0	5.3	6.0	11.0

[1] Brookfield and CSC, which are Related Persons, have elected to split their vote as follows: Brookfield - 70%; CSC – 30%.

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

ALTERNATIVE RESOURCES

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
Renewable Generation												
Gas Recovery Systems	O	O	O	O	O	O	O	F	O	O	F	O
Small RG Group Member	F	F	F	F	F	F	F	O	F	F	F	O
Distributed Generation												
Small DG Group Member	O	O	O	O	O	O	O	F	O	O	F	O
Load Response												
Comverge	A	O	O	O	O	O	O	F	O	O	F	O
Conservation Services Group	O	O	O	O	O	O	O	F	O	O	F	O
CPower	A	O	O	O	O	O	O	F	O	O	F	
EnerNOC	A	O	O	O	O	O	O	F	O	O	F	O
Vermont Energy Investment Corp.	O	O	O	O	O	O	O	F	O	O	F	O
Small LR Group Member	O	O	O	O	O	O	O	F	O	O	F	O
IN FAVOR (F)	1	1	1	1	1	1	1	8	1	1	9	0
OPPOSED (O)	5	8	8	8	8	8	8	1	8	8	0	8
TOTAL VOTES	6	9	9	9	9	9	9	9	9	9	9	8
ABSTENTIONS (A)	3	0	0	0	0	0	0	0	0	0	0	0

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

PUBLICLY OWNED ENTITY

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
Ashburnham Municipal Light Plant	A	O	O	O	O	O	O	F	O	O	F	F
Boylston Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Braintree Electric Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Chicopee Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Concord Municipal Light Plant	A	O	O	O	O	O	O	F	O	O	F	F
Conn. Municipal Electric Energy Coop.	F	O	O	O	O	O	O	F	O	O	F	F
Groton Electric Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Hingham Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Holden Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Holyoke Gas & Electric Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Hudson Light and Power Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Hull Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Ipswich Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Littleton (NH) Water & Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Mansfield Municipal Electric Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Marblehead Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Mass. Municipal Wholesale Electric Co.	A	O	O	O	O	O	O	F	O	O	F	F
Middleborough Gas and Electric Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Middleton Municipal Electric Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Pascoag Utility District	A	O	O	O	O	O	O	F	O	O	F	F
Paxton Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Peabody Municipal Light Plant	A	O	O	O	O	O	O	F	O	O	F	F
Princeton Municipal Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Rowley Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Shrewsbury Electric & Cable Ops.	A	O	O	O	O	O	O	F	O	O	F	F
South Hadley Electric Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Sterling Municipal Electric Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
Taunton Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Templeton Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Vermont Electric Cooperative	F	O	O	O	O	O	O	F	O	O	F	F
Wakefield Municipal Gas & Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
West Boylston Municipal Lighting Plant	A	O	O	O	O	O	O	F	O	O	F	F
Westfield Gas & Electric Light Dept.	A	O	O	O	O	O	O	F	O	O	F	F
IN FAVOR (F)	2	0	0	0	0	0	0	33	0	0	33	33
OPPOSED (O)	0	33	33	33	33	33	33	0	33	33	0	0
TOTAL VOTES	2	33	33	33	33	33	33	33	33	33	33	33
ABSTENTIONS (A)	31	0	0	0	0	0	0	0	0	0	0	0

ROLL CALL VOTES TAKEN AT FEBRUARY 5, 2010
NEPOOL PARTICIPANTS COMMITTEE MEETING

END USER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10	Vote 11	Vote 12
511 Plaza	O	O	O	A	O	O	O	F	A	A	F	A
CT Office of Consumer Counsel	O	O	O	O	O	O	O	A	O	O	F	O
Conservation Law Foundation	O	O	O	A	A	A	A	F	A	A	F	A
Corinth Wood Pellets	O	O	O	A	O	O	O	F	A	A	F	A
Dennis Beverage	O	O	O	A	O	O	O	F	A	A	F	A
Dragon Products Co.	O	O	O	A	O	O	O	F	A	A	F	A
Elektrisola, Inc.	O	O	O	A	O	O	O	F	A	A	F	A
Fairchild Semiconductor Corp.	O	O	O	A	O	O	O	F	A	A	F	A
Food City, Inc.	O	O	O	A	O	O	O	F	A	A	F	A
Garland Manufacturing Co.	O	O	O	A	O	O	O	F	A	A	F	A
Hammond Lumber Co.	O	O	O	A	O	O	O	F	A	A	F	A
Hardwood Products Co.	O	O	O	A	O	O	O	F	A	A	F	A
Harvard Dedicated Energy Limited	A	O	O	O	O	O	O	F	O	O	F	A
Industrial Energy Consumer Group	A	O	O	F	O	O	O	F	--	--	--	--
LaBree's	O	O	O	A	O	O	O	F	A	A	F	A
Lavalley Lumber Co.	O	O	O	A	O	O	O	F	A	A	F	A
Maine Skiing	A	O	O	F	O	O	O	F	--	--	--	--
Maine Woods Pellet Co.	O	O	O	A	O	O	O	F	A	A	F	A
Marden's	O	O	O	A	O	O	O	F	A	A	F	A
Mass. Attorney General's Office	O	O	O	O	O	O	O	F	O	O	F	F
Mead Oxford	A	O	O	F	O	O	O	F	--	--	--	--
Merchants Plaza	O	O	O	A	O	O	O	F	A	A	F	A
NH Office of Consumer Advocate	O	O	O	O	O	O	O	A	O	O	F	O
PalletOne of Maine	O	O	O	A	O	O	O	F	A	A	F	A
PowerOptions	O	O	O	O	O	O	O	F	O	O	F	A
Quality Egg of New England	O	O	O	A	O	O	O	F	A	A	F	A
RJF – Morin Brick	O	O	O	A	O	O	O	F	A	A	F	A
Robbins Lumber	O	O	O	A	O	O	O	F	A	A	F	A
St. Anselm College	O	O	O	A	O	O	O	F	A	A	F	A
St. Joseph Health Services of RI	O	O	O	A	O	O	O	F	A	A	F	A
The Energy Consortium	O	O	O	O	O	O	O	F	O	O	F	F
The Energy Council of RI	A	O	O	O	O	O	O	F	O	O	F	A
Union of Concerned Scientists	A	O	O	A	A	A	A	F	A	A	F	A
Westerly Hospital	O	O	O	A	O	O	O	F	A	A	F	A
Whole Foods Market Group	O	O	O	A	O	O	O	F	A	A	F	A
Z-TECH, LLC	O	O	O	A	O	O	O	F	A	A	F	A
IN FAVOR (F)	0	0	0	3	0	0	0	34	0	0	33	2
OPPOSED (O)	30	36	36	7	34	34	34	0	7	7	0	2
TOTAL VOTES	30	36	36	10	34	34	34	34	7	7	33	4
ABSTENTIONS (A)	6	0	0	26	2	2	2	2	26	26	0	29

CONSENT AGENDA

From the notice of actions of the Markets Committee meeting dated February 10, 2010, which has been previously circulated:[1]

1. Support revisions to Market Rule 1, Appendix F to Market Rule 1 and ISO New England Manual M-35 (Definitions and Abbreviations) which (a) clarify a set of settlement-related subjects and (b) provide consistency with the February 2009 FERC Order regarding Day-Ahead NCPC allocation methodology for External Transactions as recommend by the Markets Committee at its February 9, 2010 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved.

2. Support the FCM conforming changes to ISO New England Manual M-20 (Installed Capacity) as recommended by the Markets Committee at its February 9, 2010 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved, with 26 abstentions in the Publicly Owned Entity Sector.

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

M E M O R A N D U M

TO: Participants Committee Members and Alternates

FROM: Paul N. Belval and Michelle C. Gardner, NEPOOL Counsel

DATE: February 26, 2010

RE: Proposed NEPOOL Comments on Credit Reforms NOPR

The Participants Committee will be asked at its March 5, 2010 meeting to approve a detailed final outline of NEPOOL's response to the Notice of Proposed Rulemaking (the "NOPR") titled "Credit Reforms in Organized Wholesale Electric Markets" (Docket No. RM10-13), which will serve as the guiding framework for NEPOOL's comments to the Commission. The outline, which is attached to this memorandum, is based on discussions held with the NEPOOL Budget and Finance Subcommittee on February 10 and 23, 2010. Although such Subcommittee is not a voting committee of NEPOOL, its members have indicated general support for this outline.

A summary of the NOPR was included with the Participants Committee materials for its February 5, 2010 meeting (along with a copy of the NOPR).[1] Comments on the NOPR are due on March 29, 2010. NEPOOL Counsel, with the review of the Participants Committee Officers and the Chair of the Budget and Finance Subcommittee, will draft comments to the FERC consistent with this outline. Before being filed with the FERC, a draft of these comments will be provided upon request to any Participant advising us that s/he wishes to review the draft.

The following form of resolution may be used by the Participants Committee on this matter:

> RESOLVED, that the NEPOOL Participants Committee (i) supports positions reflected in the comment outline prepared by the Budget and Finance Subcommittee as distributed to the Committee in advance of the March 5, 2010 meeting (the "Outline"), together with any modifications to the Outline made at the meeting, and (ii) authorizes and directs NEPOOL Counsel to reflect those positions in comments filed with the FERC in response to the NOPR.

[1] A copy of the NOPR is also available on the FERC website at: http://www.ferc.gov/whats-new/comm-meet/2010/012110/E-2.pdf.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul N. Belval and Michelle C. Gardner, NEPOOL Counsel

DATE: February 26, 2010

RE: Proposed NEPOOL Comments on FERC NOPR on Credit Reforms

The following is a detailed outline of the proposed NEPOOL response to the Notice of Proposed Rulemaking (the "NOPR") titled "Credit Reforms in Organized Wholesale Electric Markets" (Docket No. RM10-13), which will serve as the guiding framework for the creation of NEPOOL's comments to the Federal Energy Regulatory Commission ("Commission"). This outline is based on discussions held with the NEPOOL Budget and Finance Subcommittee on February 10 and 23, 2010. Although such Subcommittee is not a voting committee of NEPOOL, its members have indicated general support for this outline.

A. SETTLEMENT CYCLE

- NEPOOL supports the Commission's efforts to reduce credit risk exposure. NEPOOL is already largely in compliance with the Commission's proposals to reduce settlement cycles in order to minimize such risk. The ISO's existing settlement cycle for all Hourly Charges and payments is weekly, or seven days, with invoice statements issued every Monday. Such statements include all Hourly Charges and payments for the Real-Time and Day-Ahead Energy Markets as well as for Real-Time Operating Reserve, Forward Reserves, Regulation, Emergency Sales, Emergency Purchases, and Net Commitment Period Compensation (or "uplift"). Unless otherwise noted, all payments are due to the ISO within two business days after receipt of invoice. In addition, the NEPOOL Participants Committee approved further changes to the ISO Billing Policy in May of 2009 to amend this settlement cycle for Hourly Charges to twice weekly, with statements to be issued on Mondays and Wednesdays of each week *[(such changes were filed by ISO on ____, 2010 in Docket No. ___)*].

- NEPOOL notes that invoice statements for Non-Hourly Charges and payments, e.g., those relating to the monthly markets, the Forward Capacity Market, other ancillary services, transmission services, Participant Expenses, charges under the ISO Funding Mechanisms, monthly meter adjustments, and FCM Qualification Process Cost Reimbursement Deposits, are issued on a monthly basis. Similar to Hourly Charges and payments, all payments for Non-Hourly Charges are due within two business days after receipt of invoice. In general, these charges represent on an annual basis approximately one-third of the total overall amount outstanding (with transmission service charges comprising 36% of those amounts) and are invoiced on a monthly basis primarily as a result of when billing determinant information is readily available to the ISO. In addition, most charges are incurred on a monthly basis as a function of the market or services being billed. For almost all of these charges, a change to a seven-day settlement cycle would require the ISO to bill based on estimates, subject to true-ups on a monthly basis. To the extent not already contemplated by the Commission, NEPOOL requests that any final rule issued in this proceeding clarify that there may be certain exceptions to the seven calendar day settlement cycle for charges such as those identified by the ISO where a shorter settlement cycle would result in less precise billings.

- NEPOOL further states that it has discussed from time to time the practicality of moving to daily settlement periods with ISO and at this point, would not support such change. ISO has indicated to NEPOOL that if by referencing "daily settlements" the Commission is intending to require ISOs and RTOs to bill today activity associated with yesterday's operating day, such change may involve considerable amounts of time and resources and, if so, NEPOOL believes it would divert attention from other more pressing business in the region. In addition, such move could necessitate the greater use of estimated data (subject to later true-ups), which some Participants have expressed concerns with. Nonetheless, NEPOOL remains committed to continue to look at ways to minimize credit risk exposure in the region going forward as part of its stakeholder process and in an effort to remain a leader in credit risk issues.

B. CAPS ON UNSECURED CREDIT

The Commission proposed for comment a requirement that RTOs and ISOs reduce the extension of unsecured credit to no more than $50 million per market participant and consider whether there should be a further aggregate cap to cover an entire corporate family. The Commission also proposed for comment a requirement that would eliminate unsecured credit in financial transmission rights markets. NEPOOL supports the Commission's efforts to tighten risk and credit standards, particularly in light of the recent financial crisis that started in the fall of 2008. As a result of that crisis, ISO and NEPOOL spent a considerable amount of time in the region working to address any potential risks, which effort ultimately resulted in Tariff revisions approved by the NEPOOL Participants Committee in May 2009 to eliminate unsecured credit for all market participants other than municipal market participants and transmission and distribution entities serving native load customers and to eliminate unsecured credit entirely in the FTR markets. Under the Tariff revisions approved by NEPOOL, the maximum amount of unsecured credit allowed to municipal market participants serving native load customers would be $25 million for market charges and $25 million for transmission charges and the maximum amount of unsecured credit allow to transmission and distribution entities serving native load customers would be $50 million for market charges and $50 million for transmission charges. NEPOOL notes that although the limits allowed to transmission and distribution entities appear to exceed the Commission's proposal when combined together, the amount associated with market charges would fall within the Commission's proposed limit. NEPOOL does not believe that the transmission charges, which are simply passed through ISO, are the focus of the Commission's efforts here and to the extent desired, the Commission should clarify that its limit is only applicable to market charges.

- Such proposal [*has been filed / will be filed*] with the Commission and reflects a significant compromise among the Participants after months of negotiation. NEPOOL urges the Commission to address any issues with the proposal in that proceeding, rather than issuing a blanket rule in this proceeding. As the Commission has acknowledged, several RTOs and ISOs have already undergone their own efforts to address any outstanding credit risk concerns and the Commission ought not to impose a one-size-fits-all approach to these issues, particularly in light of the substantial amount of work that has already been done in each region.

C. UNIVERSAL COUNTERPARTIES

- The Commission proposed that each RTO and ISO include in the credit provisions of its tariff revisions to clarify their status as a party to each transaction so as to eliminate any ambiguity or question as to their ability to manage defaults and to offset market obligations. NEPOOL notes at the onset that while the Commission referenced the RTO and ISO taking title to the underlying contract

positions of a participant at the time of settlement, the Commission was not intending by its proposal to specifically order such action. NEPOOL is interpreting the Commission's proposal to require each RTO and ISO to add greater clarity, to the extent necessary, in its tariff as to whether or not it is a "universal counterparty" in the settlement and netting of transactions and to further ensure that its ability to manage defaults and offset market obligations is clear. NEPOOL states that while ISO essentially coordinates the movement of wholesale electricity among its market participants, it does not at any point take title to or otherwise takes ownership of the energy on the system. The ISO Tariff does, however, contain a "set-off" provision that states that ISO will apply any amount to which any defaulting party is or will be entitled towards the satisfaction of any of that defaulting entity's debts to the ISO, NEPOOL, or other market participants.

- NEPOOL agrees with the Commission that this issue is worth further evaluation. NEPOOL notes that it has not taken any formal positions on this issue at this time. NEPOOL is aware that other RTOs and ISOs, including PJM and MISO, have commenced efforts on these issues and believes that it ought to be given the opportunity to complete its own review of this issue here in New England prior to any final rule in this proceeding. The Commission may wish to separate this issue from the other issues in this proceeding to be considered on a separate track that would allow for such review. NEPOOL does not know at this point to what extent it faces any exposure as a result of ISO not taking title to the underlying contract positions of its market participants. NEPOOL believes that it ought to have the opportunity to evaluate the extent of any risks in this region and, armed with that information, to develop any proposals to address any such risks. The Commission ought to allow New England to complete that process prior to ordering anything further as part of this proceeding.

D. MINIMUM PARTICIPATION CRITERIA

- NEPOOL generally supports the Commission's efforts to ensure that each RTO and ISO have in place minimum criteria for market participation in order to ensure that each participant has at its disposal adequate risk management capability and adequate capital to engage in trading with minimal risk, and related costs, to the market as a whole. The current ISO Tariff requires each market participant to demonstrate proof of financial viability to become a NEPOOL Participant, which includes producing certain financial statements, references, and credit reports. In addition, each market participant must complete an ISO-prescribed training course prior to participating in the auctions for financial transmission rights. Moreover, all market participants are required to comply with the ISO's Financial Assurance Policies prior to participation in the region's wholesale markets. The posting of financial assurance by entities that are not eligible for unsecured credit (by virtue of their credit ratings and the nature of their business) acts as participation criteria, since only those participants with the means to post such assurance can participate in the region's wholesale markets.

- NEPOOL has not taken a position on the extent, if at all, to which its current participation criteria are adequate and/or whether more ought to be done. NEPOOL acknowledges that as its markets continue to evolve and more products are developed, it may wish to further strengthen its participation criteria. NEPOOL urges the Commission to provide it the opportunity to further evaluate this issue given its potential impact on its markets. Any review of such issue must delicately balance the interest in reducing risks to the markets as a whole with the interest in keeping the markets reasonably open and competitive. NEPOOL notes that ISO has indicated its belief that the existing ISO Tariff may need to be revised in order to ensure compliance with the Commission's directives. NEPOOL requests that the Commission provide it the opportunity to review ISO's recommendation and to discuss that recommendation within its stakeholder processes.

E. USE OF "MATERIAL ADVERSE CHANGES" TO MANAGE RISK

- The Commission proposed to require each ISO and RTO to add greater specificity in its tariff language identifying the circumstances where it may invoke a "material adverse change" as a justification for requiring additional collateral. NEPOOL submits that the existing ISO Tariff is in compliance with this proposal insofar as it includes such circumstances. The ISO Tariff refers to such change as a "material change" in financial status and states that such change includes, but is not limited to: a downgrade to below an Investment Grade Rating by any Rating Agency; being placed on credit watch with negative implication by any Rating Agency if the market participant or guarantor does not have an Investment Grade Rating; a bankruptcy filing or other insolvency; a report of a significant quarterly loss of decline of earnings; the resignation of key officer(s); or the filing of a material lawsuit that could materially adversely impact current or future financial results. The ISO Tariff further states that in the event of a "material change," the ISO may require financial assurance and if the market participant fails to do so, the ISO may initiate termination proceedings. NEPOOL believes that ISO currently has the necessary latitude to address sudden changes in the credit profile of a market participant based on its current Tariff language (which NEPOOL notes is not expressly limited to just those enumerated circumstances above). NEPOOL urges the Commission not to prescribe any particular circumstances or remedial actions as part of this rulemaking, as such ruling could have the unintended result of actually limiting latitude and flexibility that is currently held by ISO-NE at this time.

F. GRACE PERIODS TO CURE COLLATERAL DEFICIENCIES

- The Commission proposed to require each ISO and RTO to limit the time period allowed to post additional collateral when requested. NEPOOL submits that the existing ISO Tariff is in compliance with this proposal. The ISO Tariff currently provides that when ISO requests additional collateral, a market participant has until 10 AM of the day following such request to provide additional collateral. If the market participant fails to post such collateral, then it will be found in default of the ISO's financial assurance policies and suspended from market participation.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: February 26, 2010

RE: NEPOOL Comment Outline on FERC Notice of Inquiry Regarding Variable Energy Resources ("VER NOI")

At the March 5, 2010 meeting of the Participants Committee you will asked to vote on an outline of NEPOOL comments developed in response to the Federal Energy Regulatory Commission's (the "Commission") Notice of Inquiry regarding the integration of an increasing number of variable energy resources (such as wind and solar generators) ("VERs") into the electric grid.[1] The Commission seeks comments on its VER NOI to assist the Commission in determining whether wholesale electricity tariff reforms are necessary. Comments are due on March 29, 2010, unless an extension is granted.

The Commission seeks comment, under the following topics, on the impact of integrating an increasing number of VERs into the bulk power system: (1) data and reporting requirements, including the use of accurate forecasting tools; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and, (7) redispatch and curtailment practices necessary to accommodate VERs in real time. Under each of these topics, the Commission has set forth specific questions that it would like commenters to address.

In response to the VER NOI, NEPOOL established a working group, which Cal Bowie chairs at the request of the Chairman of the Participants Committee, to explore whether NEPOOL has comments it wishes to make and, if so, what those comments should be. The VER NOI working group met on February 12 and 17, 2010, and was well attended by a cross section of NEPOOL sector representatives and other guests. In the first meeting, the working group developed an outline of comments, and in the second meeting revised that outline.

The outline was discussed with the Markets Committee at its February 23 meeting, and then voted on at the February 26 Reliability Committee meeting. At its February 26 meeting, the Reliability Committee unanimously recommended, with a number of abstentions noted, Participants Committee support for the NEPOOL comment outline. The outline as recommended by the Reliability Committee has been included with this memo. We recognize that there is an overlap of markets and reliability related topics in the VER NOI and a vote at the

[1] A copy of the VER NOI has been forwarded to you with this memo.

Markets Committee also would have been appropriate, but given the timing of NEPOOL meetings, the February 26 Reliability Committee meeting seemed to work best. In the vote at the March 5 Participants Committee, we are asking for Participants Committee support of the comments outline with direction to NEPOOL counsel to draft comments in full consistent with the outline and file them with the Commission, subject to review by the NEPOOL Participants Committee officers.

If you have questions about the VER NOI or this memo, please contact Eric Runge at: (617) 345-4735, ekrunge@daypitney.com.

The following form of resolution could be used for Participants Committee action on this item:

> RESOLVED, that the Participants Committee supports the outline of NEPOOL comments in response to the VER NOI, as distributed with the materials for the March 5, 2010 Participants Committee meeting, together with any changes agreed to at the meeting, and instructs NEPOOL counsel to draft comments in full consistent with the outline and file them with the Commission, subject to review by the NEPOOL Participants Committee officers.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources) Docket Nos. RM10-11-000

[DRAFT OUTLINE OF NEPOOL COMMENTS 2/26/10]

COMMENTS OF THE NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

(March 29, 2010)

I. INTRODUCTION

The New England Power Pool ("NEPOOL") Participants Committee submits these comments on the Commission's January 21, 2010 Notice of Inquiry regarding Integration of Variable Energy Resources. [fill in]

II. BACKGROUND

- Provide high level overview of market design and tightly integrated transmission system in NE.

- Describe current state of VER development in NE—approx. 160 MWs of wind power, xMWs of other VERs (e.g., run of river hydro) online—xMWs of VERs in queue.

- Describe status of VERs in ISO-NE markets—(1) exemption from DAM—(2) method for calculating capacity rating—(3) rules for external transactions and effect on VERs—(4) curtailment practices.

- Describe status of New England Wind Integration Study ("NEWIS") and anticipated stakeholder process to follow this year, including consideration of potential Tariff changes resulting from the NEWIS. Describe any additional wind integration studies being considered in NE.

- Describe NESCOE blueprint for renewables.

- Note increasing level of VERs and that at some point we will reach a level of penetration that will call for implementation of new rules—NEWIS study will identify that level.

- Describe process for forming the NEPOOL comments- recognize that many of the questions are premature in light of the status of the NEWIS and the stakeholder process to follow.

III. COMMENTS

A. Data and Forecasting

- Comment: NEPOOL supports the development within ISO-NE of a system of centralized forecasting and data collection for VERs to enable their further integration into the electric grid, while maintaining reliability and addressing market efficiency issues. New England has a long and successful history of centralized dispatch, system forecasting and data collection as a tightly integrated power pool. The specifics of the requirements that would support such a centralized system would need to be worked out in NE and they should be tailored to NE. Having such a system should help reduce reliability issues and the costs of addressing the variable output of VERs. In doing so, ISO-NE should explore best practices for VER data collection/dissemination and forecasting.

- Comment: ISO-NE should consider how best to coordinate data collection and forecasting for VERs with neighboring control areas. ISO-NE should work with the system operators in NY, NB, and Quebec and with NEPOOL to develop mechanisms for such data and forecasting coordination. In doing so, ISO-NE should explore best practices for forecasting VER performance over a wide area such as NE and its neighboring control areas.

- Comment: Regarding VER data collection, NEPOOL created and for several years has operated an information collection system that facilitates the integration of VERs by supporting a market for RECs and the RPS mandates of several NE states [describe NEPOOL GIS].

B. Scheduling Flexibility and Scheduling Incentives

- Comment: We have advance commitment of resources through both the day ahead market scheduling process and subsequent Reserve Adequacy Assessments to meet forecasted load accounting for uncertainties. We have security constrained economic dispatch in NE that dispatches resources on 5 minute intervals. We have DA and RT scheduling of resources in the energy market on an hourly basis. Worth looking into whether intra-hour scheduling internal to NE should be developed for VERs and all other resources. Currently, there is an effort to develop intra-hour scheduling for market participants between NE and NY (give brief description of Intra-Hour Transaction Scheduling effort and status of it). Describe status of effort and NEPOOL position, if any, regarding that effort.

C. Day-Ahead Market Participation and Reliability Commitments

- **Comment:** Refer back to fact that we have made participation in DAM voluntary for VERs. Some, however, choose to participate in DAM. VERs that do not participate in DAM are also exempt from RT deviation charge. Although exemption from mandatory participation in DAM might be appropriate, it might also be appropriate to require VERs to provide best estimate of DA schedule to ISO for forecasting purposes (see Comment A above). Related issues that NE continues to consider: (1) should VERs that do not participate in DAM be shielded entirely from NCPC allocation for deviations in RTM even as levels of VERs increase and deviations have larger consequences; and (2) all external resources must schedule in DAM and some of those external resources are VERs, which means that external VERs are treated differently than internal VERs [explain basis for this different treatment].

- **Comment:** Also, in the FCM we have a mechanism for composite capacity offers that enables synergies to be realized from different types of capacity resources (including VERs). During the development of these comments, the question was raised as to whether NE should explore the use of composite offers in other markets to gain operational and economic benefits. This is an issue of first impression for NEPOOL and has not yet received any analysis or feedback from ISO-NE as to its workability, but it might be worth exploring.

D. Balancing Authority Coordination

- **Comment:** NEPOOL has no comment at this time on whether it is desirable to create a multi-control area balancing authority for VERs; we note, however, that doing so would only make sense for NE if there are benefits for NE that are not outweighed by the costs to NE. NEPOOL would not want costs shifted from one region to another as a result of the formation of any larger balancing authority.

- **Comment:** Coordinated data collection and forecasting among neighboring control areas (see Comment A *supra*) could accomplish some of the objectives of a larger balancing authority.

- **Comment:**. The issue of reserve sharing between neighboring control areas has been considered at various times in NE over the years and bears further consideration, especially in connection with VERs.

E. Reserve Products and Ancillary Services

- Comment: We do not have sufficient information yet to answer most of the questions regarding reserves/ancillary services and VERs. The NEWIS study will provide some information about potential system problems that need to be addressed but will not make recommendations for market rule changes. Expect that ISO-NE and/or stakeholders will have such recommendations but as yet there has been no stakeholder process on these questions. We note that currently reserve products in NE are provided through markets rather than the OATT. We have also explored the usefulness of storage devices and demand response resources through pilot programs [describe the programs].

F. Capacity Markets

- Comment: When we developed the FCM design we incorporated a just and reasonable method for calculating the capacity rating of VERs. We use site specific numbers based on historical data. These numbers are revised periodically to capture actual production. Ours is a reasonable methodology that suits NE much better than standardized assumptions; we'll continue to consider whether it can be refined/improved. Don' want standard rules across country. We want to get capacity factor for NE right. Even a standard process/methodology, as distinct from standardized capacity factor, does not make sense for the nation as a whole, because different regions have different peak periods and other conditions. As for other capacity market issues, we will evaluate these after NEWIS is complete.

- Comment: We note that there are proposals to transmit the output of VERs across wide regions and multiple control areas. As the remoteness of imported capacity resources increases, there might also be increased reason to treat such capacity differently than "local" capacity. Any rules for such treatment would be subject to further ISO-NE and stakeholder consideration.

G. Real-Time Adjustments

- Comment: An issue has been raised as to whether DA tie-breaking rule used in curtailments can disadvantage VERs that do not participate in the DAM [describe]. ISO-NE's business plan for 2010 includes discussion of permitting negative energy bids to facilitate price-based resolution of congestion and decrease the reliance on tie-breaking rules. [verify] NE will consider further in connection with the results of the NEWIS.

IV. CONCLUSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources) Docket Nos. RM10-11-000

[DRAFT OUTLINE OF NEPOOL COMMENTS 2/~~25~~26/10]

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(March 29, 2010)

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- **Comment:** Also, in the FCM we have a mechanism for composite capacity offers that enables synergies to be realized from different types of capacity resources (including VERs). During the development of these comments, the question was raised as to whether NE should explore the use of composite offers in other markets to gain operational and economic benefits. This is an issue of first impression for NEPOOL and has not yet received any analysis or feedback from ISO-NE as to its workability, but it might be worth exploring.

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- **Comment:** NEPOOL has no comment at this time on whether it is desirable to create a multi-control area balancing authority for VERs; we note, however, that doing so would only make sense for NE if there are benefits for NE that are not outweighed by the costs to NE. NEPOOL would not want costs shifted from one region to another as a result of the formation of any larger balancing authority.

- **Comment:** Coordinated data collection and forecasting among neighboring control areas (see Comment A *supra*) could accomplish some of the objectives of a larger balancing authority.

- **Comment:** ~~We are exploring the use of intra-hour market transaction scheduling (see Comment B above) between NE and NY. That effort could lead to some of the benefits the Commission is considering in the questions about consolidating balancing authorities for VERs. Also, the~~ The issue of reserve sharing between neighboring control areas has been considered at various times in NE over the years and bears further consideration, especially in connection with VERs.

E. Reserve Products and Ancillary Services

- **Comment:** We do not have sufficient information yet to answer most of the questions regarding reserves/ancillary services and VERs. The NEWIS study will provide some information about potential system problems that need to be addressed but will not make recommendations for market rule changes. Expect that ISO-NE and/or stakeholders will have such recommendations but as yet there has been no stakeholder process on these questions. We note that currently reserve products in NE are provided through markets rather than the OATT. We have also explored the usefulness of storage devices and demand response resources through pilot programs [describe the programs].

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IV. CONCLUSION

130 FERC ¶ 61,053
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Chapter I

(Docket No. RM10-11-000)

Integration of Variable Energy Resources

(Issued January 21, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources (VERs) into the electric grid, and whether reforms are needed to eliminate those barriers. In order to meet the challenges posed by the integration of increasing numbers of VERs, ensure that jurisdictional rates are just and reasonable, eliminate impediments to open access transmission service for all resources, facilitate the efficient development of infrastructure, and ensure that the reliability of the grid is maintained, the Commission seeks to explore whether reforms are necessary to ensure that wholesale electricity tariffs are just, reasonable and not unduly discriminatory. This Notice will enable the Commission to determine whether wholesale electricity tariff reforms are necessary.

DATES: Comments are due **[**Insert date that is 60 days after publication in the **FEDERAL REGISTER]**.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Mk Shean (Technical Information)
Office of Energy Policy and Innovations
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6792
Mk.Shean@ferc.gov

Timothy Duggan (Legal Information)
Office of General Counsel – Energy Markets
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8326
Timothy.Duggan@ferc.gov

SUPPLEMENTARY INFORMATION:

130 FERC ¶ 61,053
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources Docket No. RM10-11-000

NOTICE OF INQUIRY

(Issued January 21, 2010)

1. In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers exist that may impede the reliable and efficient integration of variable energy resources (VERs)[1] into the electric grid and whether reforms are needed to eliminate those barriers. VERs, such as resources powered by wind and solar energy, continue to make up an increasing percentage of the nation's energy supply portfolio; however, they present unique challenges (such as location constraints and limited dispatchability) that are not typically presented by conventional electricity generating resources. VERs also present benefits, such as low marginal energy costs and reduced greenhouse gas emissions, which have contributed to the accelerated development of these resources. In order to meet these challenges and fully realize these benefits of VERs in a reliable and efficient manner, the Commission

[1] For purposes of this proceeding, the term variable energy resource (VER) refers to renewable energy resources that are characterized by variability in the fuel source that is beyond the control of the resource operator. This includes wind and solar generation facilities and certain hydroelectric resources.

seeks to explore whether reforms of existing policies are necessary to ensure that jurisdictional rates are just and reasonable and that the terms of jurisdictional service do not unduly discriminate against these resources.

I. Background

2. While the amount of VERs remains relatively small as a percentage of total generation, it is rapidly increasing, reaching a point where such resources are becoming a significant component of the nation's energy supply portfolio. In 2008, new wind generating capacity, totaling 8,376 MW, made up 42 percent of all newly installed generating capacity.[2] Moreover, in recent years, a number of state renewable portfolio standards and other incentives/mandates have been passed to encourage the development of renewable energy resources, in response to a growing concern about the environmental impacts and sustainability of the Nation's current electricity supply portfolio. As of December 2009, 30 states, including the District of Columbia, had a renewable portfolio standard.[3]

3. While VERs have many desirable characteristics, including low marginal energy costs and reduced greenhouse gas and other pollutant emissions, compared to conventional fossil-fueled generation, they also present unique challenges as public

[2] Div. of Market Oversight, Fed. Energy Regulatory Comm'n, 2008 State of the Markets Report 19 (2009), available at http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf.

[3] Div. of Market Oversight, Fed. Energy Regulatory Comm'n, Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards 1 (2009), available at http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf.

utilities work to integrate VERs in a way that ensures system reliability. For example, because VERs cannot control or store their fuel source, they have limited ability to control their production of electricity, and the weather-related phenomena that drive VER output levels can be difficult to forecast. Also, the output from some VERs can be negatively correlated with demand, such that a resource's greatest energy output often comes at a time of limited energy demand. Changes in the rate of output from VERs may also result in substantial ramps,[4] which can require additional resources to allow System Operators[5] to balance generation and demand while maintaining reliability in real time.

4. In this proceeding, the Commission seeks to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's jurisdiction may hinder the reliable and efficient integration of VERs, resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources. The Commission seeks comment on how best to reform any such rules, regulations, tariffs, or industry practices.

5. Under sections 205 and 206 of the Federal Power Act, the Commission has a responsibility to remedy undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate commerce and to ensure that

[4] A ramp is the rate, expressed in megawatts per minute, that a generator changes its output.

[5] System Operator refers to the individual at a control center—balancing authority, transmission operator, generator operator (VERs as well as conventional resources), or reliability coordinator—whose responsibility it is to monitor and control the electric system in real time.

rates for these services are just and reasonable.[6] As the electric power industry has evolved, the Commission has discharged this responsibility in different ways. In Order No. 888, the Commission exercised its authority to remedy undue discrimination by requiring all public utilities to provide open access transmission service consistent with the terms of a pro forma open access transmission tariff (OATT).[7] The pro forma OATT addresses the terms of transmission service, including, among other things, the terms for scheduling transmission service, curtailments, and the provision of ancillary services. In Order No. 2003, the Commission acted to remove barriers in the generator interconnection process and adopted standard procedures (the Large Generation Interconnection Procedures or LGIP), and a standard agreement (the Large Generation Interconnection Agreement or LGIA) for the interconnection of generation resources larger than 20 MW.[8] More recently, in a further effort to remedy the potential for undue

[6] 16 U.S.C. 824d, 824e.

[7] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[8] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), order on reh'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007). Similarly, the Commission also adopted standard procedures for the

(continued…)

discrimination, the Commission revised and updated the pro forma OATT in Order No. 890.[9]

6. With limited exceptions,[10] these and other Commission efforts to remedy undue discrimination have not expressly accounted for the differences between VERs and more conventional generation resources. In large part this is due to the fact that the electric grid was developed during a time when electricity was almost exclusively generated from centralized, dispatchable resources that were powered by fuel sources that could be stored and used as needed. The Commission's policies and the concomitant implementation of its responsibility under sections 205 and 206 were premised on this underlying physical reality of the electric grid.

7. Where relevant, however, the Commission on several occasions has taken the operational characteristics of VERs into consideration in efforts to ensure just and

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interconnection of small generation resources. Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, order on reh'g, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), order granting clarification, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[9] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[10] See, e.g., Interconnection for Wind Energy, Order No. 661, FERC Stats. & Regs. ¶ 31,186, order on reh'g, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005) (adopting reforms to the LGIA and LGIP to establish standard technical requirements for interconnection of wind plants); Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665 (establishing a standard offer generation imbalance service, but exempting intermittent resources from the highest penalty band).

reasonable rates and to remedy undue discrimination. In Order No. 661, the Commission required public utilities to revise their LGIAs and LGIPs to incorporate standard technical requirements for the interconnection of wind resources larger than 20 MW.[11] In Order No. 890, the Commission applied a reduced penalty amount to intermittent resources' imbalances that would otherwise be subject to the highest-tier generation imbalance penalties, recognizing "that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules."[12] In addition, in Order No. 890 the Commission created conditional firm point-to-point transmission service, noting that conditional firm service can be particularly beneficial to renewable energy resources.[13] Shortly after the issuance of Order No. 890, the Commission accepted a unique cost allocation mechanism for interconnection facilities connecting renewable energy resources that are location-constrained, recognizing that the difficulties faced by these resources are different from those faced by other generation developers, and therefore support an appropriate variation of the interconnection pricing policy.[14]

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[11] Order No. 661, FERC Stats. & Regs. ¶ 31,186 (adopting, among other things, a low voltage ride-through standard, a power factor range, dynamic reactive power capability, and supervisory control and data acquisition (SCADA) capability).

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 664-65.

[13] Id. P 912.

[14] Cal. Indep. Sys. Operator Corp., 119 FERC ¶ 61,061, at P 69-70 (2007). See also Southwest Power Pool, Inc., 127 FERC ¶ 61,283, at P 29 (2009) (accepting a proposal to allocate network upgrade costs differently for wind resources being used to

(continued…)

8. Such actions are premised on the notion that targeted revisions to Commission policies are sometimes necessary to ensure that jurisdictional rates are just and reasonable and to prevent undue discrimination against any one type of customer or resource as the characteristics of the nation's generation portfolio change.

II. Subject of the Notice of Inquiry

9. In this proceeding, the Commission seeks to take a fresh look at existing policies and practices in light of the changing characteristics of the nation's generation portfolio with the aim of removing unnecessary barriers to transmission service and wholesale markets for VERs (and other technologies that may aid their integration) and promoting greater efficiencies that ultimately will reduce costs to consumers. While the Commission seeks comment on numerous challenges presented by the integration of VERs, this proceeding will not address issues related to transmission planning and cost allocation, as the Commission is considering those issues in another forum.[15]

10. Our goal is not to adopt rules that favor one type of supply source over another. Instead, the Commission's purpose in this proceeding is to investigate market and operational reforms necessary to achieve two goals: first, to ensure that rates for jurisdictional service are just and reasonable, reflecting the implementation of practices that increase the efficiency of providing service; and second, to prevent VERs from

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serve demand in a different zone than the methodology used for other resources).

[15] Transmission Planning Processes Under Order No. 890, Docket No. AD09-8-000 (Oct. 8, 2009) (notice of request for comments).

facing undue discrimination. These goals are consistent with the requirements of sections 205 and 206 of the FPA.

11. In addition, the Commission must ensure that any reforms are consistent with the need to maintain system reliability in accordance with Reliability Standards proposed by the North American Electric Reliability Corp. (NERC) and approved by the Commission pursuant to section 215 of the FPA.[16] Although the scope of this proceeding is directed to market and operational reforms, in certain instances where commenters believe existing NERC Reliability Standards should be modified or new standards developed in conjunction with the market reforms considered herein, they may indicate as much, if directly related to this proceeding. In responding to the following questions, commenters should indicate how the reforms that they propose ensure the reliable operation of the grid, or would impact the reliable operation of the grid, as required by the reliability standards.[17]

III. Questions for Response

12. To ensure that all generation resources are afforded non-discriminatory access to wholesale markets and the electric power grid and that wholesale market prices and the rates for transmission service are just and reasonable, the Commission seeks comment on the perceived barriers, and suggested solutions to removing those barriers, of integrating

[16] 16 U.S.C. 824o.

[17] See id. at 824o(a)(3). We note that NERC has an ongoing stakeholder process to examine how to accommodate high levels of variable generation. See North American Elec. Reliability Corp., Accommodating High Levels of Variable Generation (2009).

VERs into the electric grid in a reliable and efficient manner. The Commission's preliminary view is that one of the most important operational issues affecting the integration costs for VERs involves the reserves necessary to address variability in VER output. Addressing this issue means examining a number of operational practices and processes that affect both the determination of the amount of reserves needed as well as the cost of those reserves. The Commission seeks comment on the impact of integrating an increasing number of VERs in the following subject areas: (1) data and reporting requirements, including the use of accurate forecasting tools; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and, (7) redispatch and curtailment practices necessary to accommodate VERs in real time.

13. The Commission does not seek to limit its inquiry and encourages all comments regarding the topics broadly discussed herein. Commenters are invited to share with the Commission their overall thoughts, including technical, commercial, and legal observations, on the challenges posed by the increasing number of VERs, operational and technical barriers faced by VERs, and the extent to which Commission policies can and/or should be revisited in light of the increasing number of VERs. Where commenters believe specific revisions to Commission rules and/or pro forma OATT provisions are necessary to implement their proposed reforms, they are encouraged to cite those rules and/or provisions with specificity and suggest revised language as appropriate. In this

Notice of Inquiry we seek information with regard to whether changes to rules or practices as applied to VERs will achieve the Commission's goals. However, there may be instances where a change to a rule or practice could also assure just and reasonable rates and address undue discrimination if applied to other resources. Therefore, we ask commenters to address whether any proposed changes to the Commission rules or OATT provisions should apply to all resources. In addition, the Commission seeks responses to the specific questions listed below.

A. Data and Forecasting

14. The scheduling and operational practices of the bulk power system are predicated on the ability to predict, with relative precision, the output of generation resources and the ability of reserve products to accommodate fluctuations in demand and emergency conditions. The rapid increase in the development of VERs has presented the industry with a variety of challenges related to predicting the exact output of VERs at any point in time.

15. These challenges could become more manageable for System Operators through the development and use of state-of-the-art meteorological forecasts, which are supplied with data from multiple diverse locations. Specifically, the implementation of enhanced forecasting tools and procedures could assist in projecting the output of VERs with greater accuracy, thereby promoting the efficient scheduling of all generation resources to meet expected demand, especially during the morning increase and evening decrease in demand. Enhanced forecasting could also allow System Operators in all regions to anticipate system ramping events more effectively and respond to them in an

economically efficient manner, thereby ensuring that jurisdictional rates are just and reasonable.

16. To assist in the development of state-of-the-art forecasting tools for VERs, the Commission seeks comment on whether and, if so, how the Commission should modify existing operational data reporting requirements. The Commission also aims to determine what data and what level of data-sharing is necessary, coupled with advanced communication and metering tools, to ensure that VERs are integrated in a reliable and efficient manner, particularly with respect to scheduling, ramping needs, and the procurement of reserve services.

17. To that end, the Commission seeks comment on the following questions:

1. What are the current practices used to forecast generation from VERs? Will current practices in forecasting VERs' electricity production be adequate as the number of VERs increases? If so, why?
2. What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?
3. What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?

4. What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the pro forma OATT would be necessary to accommodate these requirements?

5. State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publically available to aid in the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?

6. Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?

7. To what extent is a lack of data regarding the operational status and forecasted

output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

B. Scheduling Flexibility and Scheduling Incentives

1. Scheduling Flexibility

18. Existing scheduling practices were designed at a time when virtually all generation on the system could be scheduled with relative precision. With increasing numbers of VERs, System Operators appear to be relying more on expensive reserves, such as regulation reserves, to balance the variation in energy output from VERs. Improvements in scheduling procedures may offer the potential for greater efficiency in dispatching all energy resources if the degree of variability can be reduced, better anticipated, and/or planned for more precisely.

19. In regions outside of those run by regional transmission organizations (RTOs) or independent system operators (ISOs), resources typically schedule transmission service on an hourly basis and are only allowed to adjust their schedules during the hour for emergency situations that threaten reliability.[18] Because transmission schedules for VERs are typically set 20-30 minutes ahead of the hour, the forecast of output may be 90 minutes old by the end of the operating hour. Additionally, by limiting the ability of

[18] Section 13.8 of the pro forma OATT requires transmission customers to schedule use of firm point-to-point transmission service by 10:00 a.m. the day prior to operation. However, section 13.8 of the pro forma OATT gives the transmission provider the discretion to accept schedule changes no later than 20 minutes prior to the operating hour.

resources to adjust their schedules during the hour or to submit shorter scheduling timeframes, non-RTO/ISO System Operators may not be utilizing the full operational flexibility of the resources on their systems to change output levels to address the variable output of VERs.

20. In RTOs/ISOs, real-time markets are employed to address imbalance energy needs. Real-time markets utilize intra-hour economic dispatch of internal resources, which affords RTOs/ISOs the ability to respond quickly and economically to fluctuations in VER supply. However, RTOs/ISOs often schedule external resources on an hourly basis, consistent with non-RTO/ISO scheduling practices.

21. The Commission questions whether the retention of existing transmission scheduling practices as additional VERs come on-line is causing rates for reserves (as part of transmission service) to become unjust and unreasonable by inhibiting the ability of VERs to establish operationally-viable schedules and preventing System Operators from utilizing the full flexibility of their systems. Accordingly, the Commission seeks to explore whether greater scheduling flexibility, such as intra-hour scheduling, could provide benefits to the system and facilitate the reliable and efficient use of all resources.

22. To that end, the Commission seeks comment on the following questions:

1. Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?
2. What are the benefits and costs of allowing resources and transactions to

schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?

3. Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?
4. Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?
5. How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?
6. If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

2. Scheduling Incentives

23. Reforms to existing scheduling practices to promote intra-hour scheduling could enable VERs to more accurately meet their schedules, which in turn should help to ensure

that rates for reserves are just and reasonable. In order to achieve overall improvements in scheduling accuracy, particularly with respect to VERs, it is also important to ensure that such resources have the appropriate incentives to meet their schedules with real-time output to the extent feasible.

24. In Order No. 890, the Commission adopted pro forma OATT imbalance provisions that implemented a graduated bandwidth approach to imbalance penalties that recognized the link between escalating deviations and potential reliability impacts on the system.[19] The Commission exempted intermittent resources from the third tier deviation band, which required imbalances of greater than 7.5 percent of scheduled amounts (or 10 MW) to be settled at 125 percent of the incremental cost or 75 percent of the decremental cost of providing the imbalance energy.[20] Instead, intermittent resources with such imbalances would only be subject to the second tier imbalance penalties, i.e., 110 percent of the incremental or 90 percent of the decremental cost.[21] The Commission is interested in examining the experience with this exemption to determine whether it has resulted in scheduling practices that may result in an overall rate for transmission service that is not just and reasonable.

[19] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663-64.

[20] Id. P 664-65.

[21] In RTOs/ISOs, because real-time markets are used to address imbalance energy needs, VERs are typically exempt from some pro forma OATT deviation penalties.

25. To that end, the Commission seeks comment on the following questions:

1. Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs,[22] or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?
2. Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?
3. Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

C. Day-Ahead Market Participation and Reliability Commitments

1. Day-ahead Market Participation

26. The presence of a day-ahead market is a key characteristic of most RTOs/ISOs. When resources are scheduled accurately in the day-ahead market, subsequent out-of-

[22] For the purposes of this section, the term "VERs" refers to the same resources that the Commission identified as "intermittent" in Order No. 890. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 666.

market commitments are minimized and market participants can manage their financial exposure more effectively. However, VERs appear to participate in the day-ahead market on a limited basis, choosing instead to self-schedule the majority of their supply in the real-time energy markets (i.e., act as a price taker). Because day-ahead schedules are financially binding, there can be significant financial risk for VERs participating in the day-ahead market and not being able to meet these obligations in the real-time market. This may serve as a disincentive for VERs to participate in the day-ahead market.

27. In light of the increasing number of VERs, the Commission is interested in receiving comments on whether the lack of day-ahead market participation may be resulting in costly out-of-market commitments, thereby rendering rates unjust and unreasonable, as well as whether the financial risk associated with participating in the day-ahead market may unduly discriminate against VERs by inhibiting their ability to participate in such a market. Such comments should enable the Commission to determine whether reforms are necessary to facilitate VERs to participate more in the day ahead market rather than primarily in the real time market.

28. To that end, the Commission seeks comment on the following questions:

1. Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?
2. How can new or existing market design features assure that the day-ahead

market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

3. Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day ahead market rather than primarily in the real time market? If so, how?
4. Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?
5. Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?
6. Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

2. Reliability Commitments

29. Following the results of the day-ahead market, RTOs/ISOs conduct a reliability unit commitment process to ensure that sufficient generation will be available in the appropriate places to meet the RTO/ISO's estimate of the next day's forecasted demand. If the cleared resources are insufficient to meet that demand, the RTO/ISO commits additional units. Non-RTOs/ISOs conduct a similar assessment to evaluate the sufficiency of bilaterally scheduled resources.

30. Similar to the inefficiency associated with the lack of intra-hour transmission scheduling, the lack of a more frequent unit commitment process may result in unjust and unreasonable rates by causing System Operators to make inefficient reliability commitment decisions, which may cause unnecessary system uplift costs.

31. To that end, the Commission seeks comment on the following questions:

1. Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount of reserves needed and/or reduce system uplift costs? What would be the optimal time (e.g., 4 to 6 hours ahead of the operating hour) for such a process?
2. Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs? If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling

intervals resulting from such a market coincide with intra-hour schedules discussed above?

3. What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

D. Balancing Authority Coordination

32. Smaller balancing authorities may be unable to capture the benefits associated with VERs that are spread across a large and/or diverse geographical area. Accordingly, the Commission is interested in determining whether a limited ability of smaller balancing authorities to efficiently integrate VERs may result in rates that are unjust and unreasonable. Therefore, the Commission seeks to explore whether increased coordination among balancing authorities has the potential to enlarge the base of generation and demand available to customers, thereby making variability more manageable and ultimately reducing overall costs. In this proceeding, the Commission seeks comments on ways to increase customer access to energy, capacity, and reserve products through the use of pseudo-ties,[23] dynamic scheduling, and/or other tools and agreements.

33. To that end, the Commission seeks comment on the following questions:

1. Will smaller balancing authorities, when operated individually, have higher

[23] Pseudo-ties are defined as telemetered readings or values that are used as "virtual" tie line flows between balancing authorities where no physical tie line exists.

VER integration costs than geographically or electrically larger balancing authorities? If so, why?

2. Should the Commission encourage the consolidation of balancing authorities? If so, indicate the potential for and impediments to consolidation among balancing authorities and the means by which the Commission should encourage consolidation.

3. What tools or arrangements (e.g., dynamic schedules, pseudo-ties, and virtual balancing authorities) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities? What role should the Commission play in facilitating inter-balancing authority coordination?

4. What are the costs and benefits, if any, associated with the proliferation of small generation-only balancing authorities? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation-only balancing authorities?

5. The Commission is interested in receiving comments on whether the integration of VERs with small host balancing authorities may limit the benefits derived from geographical diversity and increase integration costs. Should the Commission encourage and/or facilitate the creation of a VER balancing authority, essentially a large area virtual balancing authority primarily designed to accommodate VERs across a broad geographic region? What would be the benefits and costs of creating such a large area entity?

6. Would a large area VER balancing authority be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER balancing authority?
7. What reliability impacts may be associated with the creation of a large area VER balancing authority?
8. Should a large area VER balancing authority be limited only to VERs? Why or why not?
9. Should the Commission consider establishing specific policies that support the creation of a large area VER balancing authority? If so, why?

E. Reserve Products and Ancillary Services

34. During normal operations, System Operators maintain reserve products to ensure that demand and generation are kept in balance.[24] Reserve products are generally defined by the timeframes in which they are available. In the moments-to-seconds timeframe, Frequency Response services provide an immediate arresting of the frequency decline or increase due to any system imbalance. In the seconds-to-minutes timeframe, regulation services provide maneuverable capacity (typically through automatic generation control),

[24] Contingency Reserves are used to recover from variations caused by a system disturbance but not for balancing normal variations.

and in the minutes-to-hours time frame, following services[25] allow for the rapid deployment of resources to maintain and/or restore system balance.

35. The Commission seeks to explore whether the variability associated with increased VER deployment may result in an over-reliance on expensive reserves, such as regulation reserves. The Commission seeks to ensure that reserves are being used efficiently such that the resulting rates are just, reasonable, and not unduly discriminatory. The Commission is also interested in ensuring that requirements for VERs to contribute to system reliability are not unduly discriminatory. Finally, the Commission seeks to ensure that changes to the rules or requirements do not hinder the reliable operation of the grid under the reliability standards.[26]

36. To that end, the Commission seeks comment on the following questions:

1. To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

[25] In RTO/ISO markets, following services are generally provided through real-time energy markets.

[26] See 16 U.S.C. 824o(a)(3).

2. How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?
3. Would a following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?
4. Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (i.e., contingency events) due to a loss of supply and to assure system reliability.[27] Does or should the definition of a contingency event include extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of "extreme ramping event."
5. Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?

[27] Disturbance Control Performance, Standard No. BAL-002-0 (Apr. 1, 2005).

6. Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?
7. Should the ancillary services provisions of the pro forma OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?
8. Are there new sources and/or providers for reserve products (such as inter-balancing authority pooling arrangements, demand response aggregators and/or storage devices) that can be used to maintain reliability and lower reserve costs during VER ramping events? Based on experience, are there characteristics of these new sources of reserves that would positively or negatively impact their ability to match the reserve product needs presented by the variability of VERs?
9. To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?
10. To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?
11. Should the Commission revisit the reactive power requirements set forth in

Order No. 661?[28] What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?

F. Capacity Markets

37. The procurement of capacity services, either through resource adequacy bilateral programs or centralized capacity markets, is commonplace in RTO/ISO markets.[29] Typically, VERs are eligible to receive compensation for capacity services in most RTOs/ISOs. However, due to their operating characteristics and the capacity rating rules, which vary among RTOs/ISOs, VERs are eligible to offer only a portion of their nameplate capacity. The price paid for capacity services depends in part on the amount of available capacity. Additionally, resources that participate in capacity markets typically are required to offer capacity in the day-ahead market, which, as discussed above, VERs often do not do.

38. The Commission questions whether existing rules governing capacity markets may result in rates for capacity services that are not just and reasonable. Moreover, to the extent existing rules limit the ability of VERs to provide capacity services that they are

[28] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 50-51.

[29] Centralized capacity markets exist in ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection LLC. California Independent System Operator Corp. and Midwest Independent Transmission System Operator, Inc. rely primarily on bilateral resource adequacy programs to procure capacity services.

capable of providing, the Commission seeks to explore whether such rules may be unduly discriminatory.

39. To that end, the Commission seeks comment on the following questions:

1. Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?
2. Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?
3. As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?
4. Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

G. Real-time Adjustments

40. Redispatch and curtailment protocols vary depending on the region of the country and scenario. The Commission is interested in receiving comments on whether VERs may be curtailed too frequently in response to transmission congestion, minimum

generation events,[30] and ramping events, because of a lack of clarity in curtailment protocols. Accordingly, the Commission seeks to explore whether redispatch and curtailment practices and protocols, especially as they relate to VERs, are transparent, non-discriminatory and efficient. The Commission also seeks to determine whether redispatch and curtailment protocols may result in unnecessary costs, thereby rendering rates unjust and unreasonable.

41. To that end, the Commission seeks comment on the following questions:

1. How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?
2. Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?
3. Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?
4. Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

[30] During a minimum generation event, system demand is at its lowest and generation resources tend to operate at the minimum feasible output level.

5. Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?
6. To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

IV. Comment Procedures

42. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice.

43. Comments are due [Insert date that is 60 days from publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM10-11-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

44. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word

processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

45. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

46. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

V. Document Availability

47. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

48. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

49. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission. Commissioner Norris voting present.

(S E A L)

Kimberly D. Bose,
Secretary.

M E M O R A N D U M

TO: Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: February 26, 2010

RE: NEPOOL Comments Regarding FERC Staff's Proposed RTO Metrics and Additional Information

---

The Participants Committee will be asked at its March 5, 2010 meeting to approve comments developed in response to a February 3, 2010 notice issued by FERC staff in Docket No. AD10-5. In that notice, FERC staff requested comments on RTO/ISO performance metrics and additional information on which RTO/ISOs will be expected to report. Comments on whether the proposed metrics will effectively track the performance of RTO/ISO operations and markets are due by Friday, March 5, 2010.

As reported at the February 5 Participants meeting, a February 16 workshop to address the proposed Metrics was facilitated by Mr. Hans Mertens of the Vermont Department of Public Service for NECPUC and Mr. Paul Peterson for NEPOOL. A follow-up meeting of the *ad hoc* RTO Metrics Working Group was subsequently held on February 25. Largely based on the input and direction received during those meetings, we are preparing proposed comments. An outline of the proposed comments and observations has been prepared and is included with this memorandum.

A draft of the proposed comments will be finalized early next week and will be circulated to the Participants Committee in advance of the March 5 meeting. As noted above, comments are currently due the same day of the Participants Committee meeting. Accordingly, if there are any questions or additional comments, please let me know as soon as possible (pmgerity@daypitney.com; 860-275-0533).

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

> RESOLVED, that the Participants Committee supports the comments developed in response to the February 3, 2010 FERC Notice in Docket No. AD10-5 requesting comments on proposed RTO/ISO Performance Metrics, as distributed to the Committee in advance of the March 5, 2010 meeting (the Comments), together with [any changes agreed to at this meeting, and] such other non-substantive changes as the Chair or any Vice-Chair of the Committee may approve, and authorizes and directs NEPOOL Counsel to file such Comments with the FERC.

Outline of NEPOOL [and NECPUC] Comments on
RTO Performance Metrics

I. Introduction and Background

- GAO Report
- Description of NEPOOL [and NECPUC]
  - New England experience with metrics/performance review. We've thought a lot about this in New England. PA itself requires this sort of analysis/evaluation of and by ISO-NE. [explain PA provisions]
- New England Stakeholder Process to consider FERC's proposed RTO metrics
  - Formed a working group – comprised of representatives from NEPOOL, NECPUC, NESCOE and ISO-NE
  - 2 teleconference meetings
  - Open process where stakeholder comments were received and discussed at highest level
- Overview of Comments
  - In the limited time that New England stakeholders have had since the February 3 notice to consider the metrics and additional information proposed by FERC staff, a general consensus around certain high level principles emerged. Those principles are outlined in the general comments offered below.
  - The Filing Parties emphasize that the comments they are submitting represent a preliminary regional perspective. The comments are necessarily constrained by the very limited comment period provided. Individual stakeholders undoubtedly will have their own views and perspectives that may be different and potentially divergent from those expressed here, and comments reflected herein should in no way be construed to constrain or prejudice the positions of individual stakeholders.
  - As will be apparent from the observations included as Attachment 1, many stakeholders have suggested a number of areas where additional guidance, refinement, and/or development might be useful.
  - NEPOOL [and NECPUC] includes, as an attachment to these comments, a summary of the observations received during its limited and preliminary stakeholder process. The Filing Parties intend these observations as information for the Commission to consider, but neither endorse nor oppose any of those observations in particular.
  - With the benefit of additional time, information, and guidance from the FERC, New England stakeholders look forward to an opportunity to further explore and provide feedback on metrics, general and specific, as well as on additional information to be collected.

II. General Comments

- NEPOOL appreciates and supports the initial efforts of FERC staff to identify RTO performance metrics. Many of the proposed metrics will likely be useful in the evaluation of

RTO performance. Much of the requested information will inform and support the analysis of trends in the organized markets.

- New England stakeholders are in general agreement that the February 3 draft is a valuable first step in the evolutionary process to develop metrics against which to evaluate RTOs

- New England supports and encourages a robust and comprehensive flow of information from the regions to the FERC

- In discussion concerning the specific metrics proposed, stakeholders considered the extent to which each metric would be suitable for or effectively track the performance of ISO/RTO operations and markets. There was a general sense that many of the proposed metrics would provide useful and important information

- Specific Observations are noted in the attached summary.

- However, stakeholders noted the importance of thoughtfully and precisely defining metrics. "Metrics" must be related and relevant to RTO performance, i.e.
    - must be meaningful in the evaluation of an RTO
    - must be reasonably attributable to or address areas influenced by RTO operations/markets
    - must support performance and/value assessment, providing actionable data, and/or supporting trend analysis
    - where an RTO's performance can be appropriately measured, progress addressing any identified deficiencies or needed improvements should also be measured

- Stakeholders identified open questions concerning areas the FERC has not, as yet, clarified. Among the open questions were the following:
    - how the metrics and additional information will be evaluated (good/acceptable, bad/unacceptable, other); what outcomes are desired or will be encouraged
    - how regional variations will be incorporated and accounted for in the valuation process
    - general agreement that appropriate metrics of RTO operations and market performance will emerge and evolve as data is collected, evaluated, and reported.

III. Observations

- In light of the preliminary understanding of the proposed metrics and additional information, and without the benefit of the information to be submitted and reported in April, New England's stakeholders provide the following observations, which were communicated in the working group process, in the hopes that some or all of them may inform and assist FERC staff in the metric development process

Performance Metrics

1. Reliability

General

- Many of the proposed metrics address planning and processing issues. While much of the information would appear to be useful information, since RTOs do not build transmission or generation, the proposed metrics do not appear to be well-suited as RTO performance metrics.

- Metrics should focus on RTO operation of the system:

  - dispatch response to disturbances
  - maintenance scheduling – reliability and cost impacts
  - correction of identified deficiencies
  - performance re: (weather normalized) load forecasting

A. Compliance with NERC or Regional Reliability Standards

- Additional metric proposed: require RTO's to identify any Reliability Standard waivers requested by/granted to an RTO

B. Dispatch Reliability

- The # of transmission load reliefs or unscheduled flows does not necessarily evaluate efficient outcomes and may not be wholly applicable to New England

C. Operational Planning – Load Forecast Accuracy

- No specific comments noted

D. Long-Term Reliability Planning – Transmission

- Generally, these issues are outside of an RTO's control. Specific metrics 1 and 2 are affected by the role played by Transmission companies. Accordingly, the specific metrics need to be revised to distill and/or distinguish RTO from TO performance.

- Suggested additional specific metrics include:

  - Evaluation of size and nature of facilities constructed
  - Evaluation of overall costs incurred
  - List and description of all NERC Reliability Standards mitigation plans outstanding and/or being conducted
  - # of MWs under out-of-market/RMR contracts
  - Accuracy of RTO planning documents/system plans, including estimated versus actual construction costs

E. Long-Term Reliability Planning – Generation

- Re: E.1 (processing times for generation interconnection requests): Processing time can vary on a case-by-case basis. It was suggested that the metric be revised to

include an evaluation of the time taken to complete processing compared against timeframe originally projected/promised.

- Re E.2. (reserve margins)
  - Might be better suited as additional information
  - Additional metrics suggested or information requested:
    - comparison of actual to required margins
    - measure the number of hours that that RTO-permitted scheduled maintenance resulted in congestion and high energy costs, particularly during shoulder periods
    - measurement of how transmission built (in constant dollars) compares to the values estimated in the RTO's transmission plan
    - measurement of whether congestion or savings accrued as projected

F. Transmission Outage Coordination

- Need to differentiate between reasons for outages – for instance, outages cancelled in anticipation of major storms should not be used
- Better metric might well be to identify those transmission outages that effect generation availability – such a metric would illustrate T&G coordination (a more efficient outcome)
- F.3 may be too related to conditions outside of RTO control (e.g. weather or other unanticipated system conditions) to be an appropriate metric
- F.4 demonstrates frequency of outages scheduled on short notice by TOs and has very little to do with ISO/RTO performance
- Suggested additional metrics:
  - if an RTO has internal goals relating to fuel diversity, data tracking fuel diversity (if not, may still have informational value)
  - # of transmission outages that get put into monthly FTR calculations and how many get used (to demonstrate how often Participants were required to hedge against something that ultimately wasn't needed)

2. Markets

General – Addition of Market Monitoring Metric

- The RTO Market Monitoring function should be included in metrics
- A Market Monitoring metric could be developed to include a report on the number of times the Market Monitor has investigated conduct, directed action, as well as the number of MWhs and $$$ involved, or qualitative explanation of outcome of investigation.

A. Market Pricing:

- A.1 (load-weighted LMPs)
  - In general, LMPs not believed to be indicative of RTO market performance

- This specific metric would need clarification in light of fact that regions manage this data differently
- ISO Market Monitor is likely to submit comments to FERC indicating how the metric can be revised to better evaluate efficiency of market prices/LMPs (e.g. use the Lerner Index
- A participant suggested a better evaluation of market price efficiency might be a comparison of the price of marginal reserves dispatched compared to the LMP
- Pricing effects should be evaluated (identifying, if at all, any price suppression)
- Percentage of out-of-merit dispatch could be identified as a specific metric, though what is good/acceptable, or bad/unacceptable performance would need to be clarified

- A.2 (components of total power cost)
  - Add to the components of total power costs to be separately identified:
    - capacity costs;
    - NCPC,
    - costs of RMR contracts,
    - de-list bids;
    - uplift costs as a percentage of overall costs
  - Complete list of all de-list bids that have been rejected for reliability reasons for Capacity Commitment Period (including the total dollars expended over and above that which would have been paid on a purely competitive basis, number of MWhs, and excess cost per MWh for each rejected de-list bid)
  - Alternative Measurements:
    - NCPC MWs and MWhs paid by resource (identity masked) in the past twelve months -- provides a better indicator of the extent to which the LMP algorithm reflects the price of energy and the extent to which RAA commitments interfere with RT pricing.
    - RAA commitments –frequency, magnitude (MW) and duration (MWhs)
    - relative percents of energy traded in Day-Ahead and Real-Time markets

- A.3 (Load-Weighted, Fuel-Adjusted LMPs)
  - Again, interesting data, but not indicative of RTO/ISO or market performance (marginal prices more dependent on generation fuel at the margin than RTO performance)

B. Generator Availability

- B. Forced Outage Rate – not viewed as a relevant metric. More reflective of the effects of prices and maintenance, rather than ISO performance

C. Congestion Management

- C. Fine to include congestion costs reflected in the LMP, but even more important to reflect the congestion costs reflected in NCPC payments. • Markets C. To price convergence, I'd add a metric for the relative percents of energy traded in day ahead and real time markets;

- it would be worth knowing whether the benefits from congestion relief exceed the cost of the fix.

D. Demand Response and E. Renewables

- While useful information, move from specific metrics to additional information – as they do not reflect RTO performance
  - ISO is not sole or best source of demand resource information (e.g. behind-the-meter demand reduction may be held by state PUCs)
  - high levels of DR participation could reflect Market Rules which place other resources at a disadvantage).
  - not clear how the amount of demand response or renewables, if properly identified, would be evaluated – good or bad
- ISO performance should be focused on a measure assuring that DR (and all other resources) has a reasonable opportunity to participate in the market.
- Cost of renewables is not identified or factored in
- Renewables metric is technically flawed. It should either be megawatts as a percentage of total capacity, or megawatt hours as a percentage of total energy.

3. Organizational Effectiveness

A. Administrative Costs

- Additional information to report – how the costs change year to year; and to the extent possible, what capital costs would be over the subsequent 5 years
- A metric designed to evaluate whether market prices are "good or bad" for consumers or suppliers might be useful

B. Customer Satisfaction

- If data to be obtained through customer surveys, avoid undue subjectivity in survey questions and analysis
- Percentage of satisfied customers should be broken down into categories, e.g.:
  - transmission planning,
  - establishment of tie benefits,
  - administration of market
  - market Rule changes,
  - market settlement,
  - market development
  - responsiveness to requests for qualitative and quantitative analyses
- Categories should also be separately ranked by Sector
- Additional metric: number of contested/uncontested FERC filings by an RTO (indicative of success of stakeholder process)

C. Billing Controls

- no comments

D. Additional Information

- It would be useful would include membership demographics (e.g. number of sectors/categories/classes of customer, number per class, applicable fees, stakeholder committee structures) to enable comparison of level and extent of participation in RTOs
- Transmission Cost Controls -- it would be useful to tract the cost of new and upgraded transmission facilities and establish metrics (e.g., cost/MWcapacity) to measure effectiveness of ISO/RTO oversight

II. Additional Performance Metrics

A. Responsiveness to Participants and Consumer Concerns:

- Responsiveness to participant or consumers' requests for qualitative and quantitative cost impact analyses (include statistics on number of requests and number of responses, as well as narrative summarizing each request and response)
- Responsiveness to participants' requests for analyses of market rule revision alternatives (include statistics on number of requests and number of responses, as well as narrative summarizing each request and response)
- This information will be helpful in evaluating performance in (i) responding to requests for cost impact analyses; and (ii) responding to requests for analyses of market rule revision alternatives.

B. Costs to Consumers:

- Overall delivered costs to consumers (total amount and per MWh delivered)
- Break down of delivered costs to consumers by total transmission, energy, and capacity costs delivered (total amount and per MWh delivered)
- Further breakdown of costs from previous metric by reliability region (total amount and per MWh delivered)
- This information will be helpful in evaluating the cost-effectiveness of RTO initiatives

IV. Additional Information

The following additional information was suggested for inclusion in Section 2 – "Additional Information" (on which the RTOs will report):

- A Cost Effectiveness Category - overall cost to consumers
- Transmission cost per MWh delivered … cost of wires/MWh
- System load factor measurements
- Demand Response data quantifying
    - the benefits of DR

  - to what extent various wholesale markets are open to DR -- enabling comparison of opportunities available to DR and generation resources; demonstrating comparability of treatment

- Impact on additional reserve margin attributable to the addition of intermittent resources
- Trend analysis of Day-Ahead and Real Time LMP vs. natural gas and #6 fuel oil prices by month

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: February 26, 2010

RE: Revisions to Operating Procedures and Planning Procedures

---

At the March 5, 2010 meeting of the Participants Committee you will asked to vote on revisions to ISO-NE Operating Procedures and Planning Procedures (collectively, the "Procedures") that bring those Procedures into accord with NERC requirements for coordination between nuclear plant operators and transmission entities for ensuring safety of plant operations and shutdown. Marked versions of the Procedures have been included with this memo.

The Reliability Committee reviewed the revisions to the Procedures and, at its February 26, 2010 meeting, voted unanimously to recommend Participants Committee support of them. The recommendation would have otherwise been on the Consent Agenda but for the timing of the Reliability Committee action.

The following form of resolution could be used for Participants Committee action on this item:

> RESOLVED, that the Participants Committee supports the revisions to the following ISO New England Operating Procedures (OPs) and Planning Procedures (PPs) that bring those Procedures into accord with NERC requirements for coordination between nuclear plant operators and transmission entities, as recommended by the Reliability Committee and circulated to this Committee in advance of this meeting, together with [any changes agreed to at this meeting, and] such other non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve:
>
> - OP 1 Appendix A (Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and Market Participants)
> - OP 14 (Technical Requirements for Generators, Demand Resources and Asset Related Demands), including Appendix 14A (Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12, Generator Technical Data)
> - PP 3 (Reliability Standards for the New England Area Bulk Power Supply System)
> - PP 5-1 (Procedure for Review of Governance Participant's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures and Forms))
> - PP 5-3 (Guidelines for Conducting and Evaluating Proposed Plan Application Analysis)

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the Local Control Centers or Market Participants of normal operating data, Regulation capability or voice communications. This is further defined in ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering, and Computer Support Equipment (OP2).

XIX. NUCLEAR PLANT INTERFACE COORDINATION AND OPERATION

A. ISO NEW ENGLAND

1. Verify receipt of Nuclear Plant Interface Requirements (NPIRs), as defined in ISO New England Operating Procedure No. 14 - Technical Requirements for Generation, Demand Resources and Asset Related Demands (OP-14).

2. Monitor applicable limits, conduct operational analyses, communicate and coordinate information about the transmission system as pertains to the NPIRs.

3. Coordinate outages and maintenance activities which affect the NPIRs with the Nuclear Plant Generator Operator.

4. Notify appropriate Local Control Center(s) and Nuclear Power Plant whenever ISO identifies a system limitation or configuration, as has been identified by the Nuclear Power Plant through OP-14 and agreed to by ISO, that may affect the NPIRs.

5. Notify appropriate Nuclear Power Plant when both ISO and the applicable LCC lose the ability to assess the operation of the electric system affecting the NPIRs.

6. Inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the bulk electric system to meet the NPIRs.

7. At least once every three years, review applicable provisions of the Transmission Operating Agreement, Market Participant Services Agreement, Interconnection Agreements and Operating Procedures related to how the NPIRs are addressed, implemented, incorporated into operations analyses and included in training programs. These Agreements include administrative elements, technical requirements and analysis, operations and maintenance coordination, communication protocols and training programs necessary to implement the NPIRs.

8. Incorporate NPIRs into training programs.

B. LOCAL CONTROL CENTERS

1. Monitor applicable limits, conduct operational analyses, communicate and coordinate information about the transmission system as pertains to the NPIRs.

2. Inform ISO and the Nuclear Power Plant of any operating condition that has the potential to violate the NPIRs.

3. Coordinate outages and maintenance activities which affect the NPIRs with the Nuclear Plant Generator Operator.

4. Incorporate NPIRs into training programs.

C. MARKET PARTICIPANTS

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1. The Nuclear Power Plant Market Participants are solely responsible for meeting the licensing and environmental requirements for the facilities they own and operate unless otherwise assigned.

2. The Nuclear Power Plant Market Participants must supply the ISO and applicable Market Participants with the NPIRs in accordance with applicable ISO Operating Documents including OP-14.

3. The Transmission Owner Market Participants are required to inform the LCC of any operating condition that has the potential to violate the NPIRs, and are also required to supply ISO with facility parameters and limits in accordance with ISO Operating Documents including ISO New England Operating Procedure No. 16 - Transmission System Data (OP-16). Such information is essential to provide accurate models needed by the ISO and LCCs to conduct operational analyses.

4. The Nuclear Power Plant Market Participants and the Transmission Owner Market Participants shall coordinate outages and maintenance activities which affect the NPIRs with the ISO and applicable LCC.

5. The Nuclear Power Plant Market Participant and the Transmission Owner Market Participant shall incorporate NPIRs into training programs.

6. The Nuclear Power Plant Market Participants and the Transmission Owner Market Participant shall coordinate on the development and submittal to ISO of the one-line diagram(s) in accordance with ISO OP-16. Such one-line diagram(s) shall include a representation of the configuration of the electrical facilities and components at the interface between the electric system and the nuclear plant that are essential for meeting the NPIRs, and shall also identify and delineate ownership and operational jurisdiction of facilities.

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OP 1 APPENDIX A REVISION HISTORY

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

Rev. No.	Date	Reason
Rev 1	01/04/03	Updated by John Norden
Rev 2	02/01/05	Updated to conform to RTO terminology
Rev 3	10/01/06	Updated for ASM Phase 2
Rev 4	12/21/07	Revised as part of annual review
Rev 5	12/4/09	Added new Section XIX to updated for NUC-001

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NEPOOL Form NX-12: Generator Technical Data

Revision: 5.0 Draft

Lead Participant	Local Control Center	Generator Name	Unit #	Gen/Asset ID
	Click here to select the LCC			

Designated Entity	DE Location	DE Contact Name	DE Phone #	DE E-Mail

1. Data Preparation Documentation

Data Revision No. ____ Date Prepared _____

Prepared By _____ Requested Effective Date _____

(e-mail) _____

2. Basic Information

Generator Type:
Click here to select Type

Startup Fuel Type:
Click here to select Type

Predominant (Primary) Fuel Type:
Click here to select Type

Secondary (Alternate) Fuel Type:
Click here to select Type

Heat Rate (Btu/kWh): _____

Metering Domain ID: _____

Status:
1. Active Unit ____
2. Retired Unit
3. Deactivated Reserve
3.a Deactivated Reserve Unit ____
3.b Deactivated Effective Date _____

Capabilities:
1. Black Start resource
1.a Black Start Enabled resource (BSEr) ____
1.b Black Start Restoration Plan resource (BSRPr) ____
2. ICAP Resource ____
3. Biddable ____
4. Dispatchable ____
5. Claim 10 Capable ____
6. Claim 30 Capable ____
7. Fast Start Capable ____

Fuel Switch:
1. Online Fuel Switch Capable ____
2. Preparation Time (Hours) ____

3. (Seasonal Claimed) Capability (SCC)

Winter Claimed Capability _____ MW Summer Claimed Capability _____ MW

(Please provide monthly Capability values for Daily Cycle Hydro and Wind Turbine facilities)

January		MW
February		MW
March		MW
April		MW
May		MW
June		MW
July		MW

NEPOOL Form NX-12: Generator Technical Data

Revision: 5.0 Draft

Lead Participant	Local Control Center	Generator Name	Unit #	Gen/Asset ID
	Click here to select the LCC			

Designated Entity	DE Location	DE Contact Name	DE Phone #	DE E-Mail

Additional Information Required for Nuclear Power Plants ONLY (based on licensing requirements):

a. Minimum post unit trip voltage (kV): _____ Time (sec): _____

b. NPP station service load details:

c. Specific NPP systems that require ISO and/or LCCs to coordinate operations and maintenance with the NPP:

d. Transmission facilities that requires ISO and/or LCCs to coordinate operations and maintenance with the NPP:

e. Operating scenarios based on licensing requirements that require communication from the NPP to ISO and/or LCC:

f. Operating scenarios based on licensing requirements that require communication from ISO and/or LCC to the NPP:

APPENDIX A

EXPLANATION OF TERMS AND INSTRUCTIONS FOR DATA PREPARATION OF ISO NEW ENGLAND FORM NX-12, GENERATOR TECHNICAL DATA

GENERAL INFORMATION

The NX-12 Generator Technical Data form requests information needed by ISO New England (ISO) that is not a part of the bid information. All required data must be provided for each defined Generator, as per OP-14, Section II.A.

Once an initial NX-12 has been provided, any change in Generator data must be reported to ISO via a revised NX-12 form. All NX-12 submissions will be sent to opanx12@iso-ne.com.

In order for an NX-12 form to be approved by ISO, all required data must be provided without errors and without omissions. It is the responsibility of the Lead Market Participant to correct errors or omissions on an NX-12 form and re-submit the corrected form to ISO. ISO will be the sole judge of when an NX-12 form is complete and correct. The effective date for changes to data items on an NX-12 form must be at least seven (7) days from the date that such determination is made by the ISO that the NX-12 form is complete and without errors.

When requested to select from a list of items, please indicate your selection by entering an "x" in the appropriate space on the NX-12 form.

Revision – Form revision identification and date of revision.

Lead Market Participant – The Lead Participant of a Generator as defined in ISO New England Manual for Definitions and Abbreviations, Manual M-35.

Local Control Center – The Local Control Center (LCC) with Operating Responsibility and Authority of a Generator as defined in ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and the Market Participants (OP 1).

Generator Name – The name of the Generator must:

- Be unique to all Generators
- Length cannot exceed 30 characters

Unit # – The unit number supplied by the ISO, or combination thereof, which represents the *entire* Generator in the ISO Market System and Energy Management System (EMS). For example, a Generator Name and Unit # combination may be:

- Manchester 10/10A; or
- Montville 10 & 11,

Where, each of these combinations represents *one Generator Asset*.

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Section 8: Additional Information – List any additional information regarding the Generator that is not previously detailed in this form or the Bid Parameters

Additional Information Required for Nuclear Power Plants ONLY - Market Participants submitting an NX-12 for Nuclear Power Plants (NPP) must include information regarding the Nuclear Plant Interface Requirements (NPIR) which are based on Nuclear Plant Licensing Requirements and Bulk Electric System requirements. The ISO reserves the right to request documentation of how each requirement in (a) through (f) below corresponds to one or more Nuclear Plant Licensing Requirements. The NPIRs that pertain to ISO and the LCCs include data and requirements relative to both generation and transmission. The NPIRs to which the ISO has agreed are entirely contained in the approved ISO Form NX-12 for generation data.

Specific NPIR information included on the NX-12 form is as follows:

a. Based on licensing requirements, the minimum voltage required at the transmission switchyard after the nuclear unit has tripped and time (optional) within which the voltage must be provided.

b. NPP station service load details. Additional information regarding AC power requirements of the NPP during and after transients such as a unit trip, restoration during and after a station blackout, etc. Note that normal station service load is documented in Form NX-12D.

c. Specific NPP systems that require ISO and/or LCCs to coordinate operations and maintenance with the NPP. For example, systems at the NPP that should not be scheduled to be out of service simultaneously with the outage of a transmission line (i.e., emergency diesel generators, critical cooling systems, startup or shutdown transformers, etc.).

d. Transmission facilities that require ISO and/or LCCs to coordinate operations and maintenance with the NPP. For example, transmission lines which provide off-site sources of power.

e. Operating scenarios based on licensing requirements that require communication from the NPP to ISO and/or LCC. For example, the NPP may be required to notify ISO and the LCC when the NPP enters a shutdown Limiting Condition of Operation (shutdown LCO) or when critical equipment is removed from service.

f. Operating scenarios based on licensing requirements that require communication from ISO and/or LCC to the NPP Operator: For example, the NPP may require notification when ISO and the LCC lose the ability to analyze post trip voltage at the switchyard or when one of the off-site sources of power to the NPP is unavailable.

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OP 14 Appendix A Revision History

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

Rev. No.	Date	Reason
Rev 1	01/05/05	
Rev 2	02/01/05	Updated to conform to RTO terminology
Rev 3	10/01/06	Updated for ASM Phase 2
Rev 4	10/10/08	Various editorial and terminology changes to be consistent with current used terminology, defined acronyms and correct reference procedure titles. Changes to include Fuel Type and add more Generator Types to be consistent with changes to NX-12. In GENERAL INFORMATION Section: Added new term - Revision and its definition. Added Market to Lead Participant. In Unit# added "supplied by ISO" after "The unit number…" Added the following terms and explanation in Section 2 – Basic Information: Heat Rate: 1) Added to the end of the first sentence "(EcoMax) at the units SCC nominal temperature rating." 2) Added sentence to end stating "Btu/kWh can be rounded up to the nearest 100 Btu's. Status: Added 3.Deactivated Reserves; 3.a Deactivated Reserve Unit; and 3.b Deactivated Effective Date (and definition) Capabilities: 1) Black Start Enabled resource (BSEr) 2) Black Start Restoration Plan resource (BSRPr) 3) Heat Rate Fuel Switch: 1) Changed "Notification Time:" to "Preparation Time:" Added "including swap time" to the end of the first paragraph. Added the following term and explanation in Section 3: Seasonal Claimed Capability (SCC) In both **Winter Claimed Capability –** and **Summer Claimed Capability -** changed **"Kilowatts" to "Megawatts"** • Black Start Emergency Min Changed the title in the first paragraph of Section 4 to "Regulation Market Capable"
Rev 5	Draft	Added a new Additional Information Required for Nuclear Power Plants sub-section to Section 8 to SPECIFIC INFORMATION to update for NUC-001

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ISO NEW ENGLAND PLANNING PROCEDURE NO. 3

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

EFFECTIVE DATE: ~~June 11, 2009~~February 18, 2010 Draft

REFERENCES:

~~NERC Version 0 Reliability Standards~~

~~NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, Revised May 6, 2004~~

NPCC Reliability Reference Directory # 1 Design and Operation of the Bulk Power System, December 1, 2009 (Includes references to NERC ERO Reliability Standards)

~~NPCC Document A-3, Emergency Operation Criteria, Revised August 31, 2004~~NPCC Regional Reliablity Reference Directory # 2 Emergency Operations, October 21, 2008

~~NPCC Document A-5, Bulk Power System Protection Criteria, Revised January 30, 2006~~

NPCC Reliability Reference Directory # 4 Bulk Power System Protection Criteria, December 1, 2009

NPCC Document A-7, Glossary of Terms, Revised July 17, 2007~~February 6, 2006~~

~~NPCC Document A-11, Special Protection System Criteria, Adopted November 14, 2002~~

NPCC Regional Reliability Reference Directory # 7 Special Protection Systems, December 27, 2007

ISO New England Planning Procedure 5-5, Special Protection Systems Application Guidelines

Damping Criterion Basis Document, Stability Task Force, Approved April 1, 2009.

NERC NUC-001-2, Nuclear Plant Interface Coordination Reliability Standard, Adopted by NERC Board of Trustees: August 5, 2009

NERC Glossary of Terms Used in Reliability Standards, Updated April 20, 2009

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

1. INTRODUCTION

The ISO New England Transmission, Markets and Services Tariff (the "Tariff") provides for the establishment of reliability standards for the bulk power supply system of the New England Area. The reliability standards set forth herein have been adopted as appropriate for the New England **bulk power supply system**[1]**.** Further, they are consistent with those established by the Northeast Power Coordinating Council in the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" and the NPCC "Bulk Power System Protection Criteria."

The purpose of these New England Reliability Standards is to assure the reliability and efficiency of the New England **bulk power supply system** through coordination of system planning, design and operation. These standards apply to all entities comprising or using the New England **bulk power supply system**. The host Governance Participant (the Governance Participant through which a non-Governance Participant connects to the **bulk power supply system**) shall use its best efforts to assure that, whenever it enters into arrangements with non-Governance Participants, such arrangements are consistent with these standards.

These Reliability Standards establish minimum design criteria for the New England **bulk power supply system**. It is recognized that more rigid design and operating criteria may be applied in some segments of the pool because of local considerations. Any constraints imposed by the more rigid criteria will be taken into account in all testing. It is also recognized that the Reliability Standards are not necessarily applicable to those **elements** that are not a part of the New England **bulk power supply system**.

Because of the long lead times required for the planning and construction of generation and transmission facilities versus the short lead times available for responding to changed operating conditions, it is necessary that criteria for planning and design vary in some respects from the System Rules used in actual operations. The intent is to have the system operate at the level of reliability that was contemplated at the time it was designed. For this reason, it is necessary that the design criteria simulate the effects of the equipment outages which may be expected to occur in actual operation. Nevertheless, it should be recognized that in actual operations, it may not always be possible to achieve the design level of reliability due to delays in construction of critical facilities, excessive forced outages, or loads exceeding the predicted levels.

[1] Terms in bold typeface are defined in Appendix A.

These Reliability Standards are intended to be used for planning and design of the New England **bulk power system**. Reliability criteria and procedures for operations are detailed elsewhere, with the primary reliability-related documents used in system dispatch and operations being:

1. ISO New England Operating Procedure No. 1 – Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and Market Participants
2. ISO New England Operating Procedure No. 3 – Transmission Outage Scheduling
3. ISO New England Operating Procedure No. 4 – Action During a Capacity Deficiency
4. ISO New England Operating Procedure No. 5 – Generation Maintenance and Outage Scheduling
5. ISO New England Operating Procedure No. 6 – System Restoration
6. ISO New England Operating Procedure No. 7 – Action in an Emergency
7. ISO New England Operating Procedure No. 8 – Operating Reserve and Regulation
8. ISO New England Operating Procedure No. 11 – Black Start Capability Testing Requirements
9. ISO New England Operating Procedure No. 12 – Voltage and Reactive Control
10. ISO New England Operating Procedure No. 13 – Standards for Voltage Reduction and Load Shedding Capability
11. ISO New England Operating Procedure No. 14 – Technical Requirements for Generatorsion, Demand Resources and Asset Related DemandsDispatchable and Interruptible Loads
12. ISO New England Operating Procedure No. 17 – Load Power Factor Correction
13. ISO New England Operating Procedure No. 18 – Metering and Telemetering Criteria
14. ISO New England Operating Procedure No. 19 – Transmission Operations

The New England **bulk power supply system** shall be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable **contingencies**. Therefore, the system is required to be designed to meet representative **contingencies** as defined in these Reliability Standards. Analyses of simulations of these **contingencies** should include assessment of the potential for widespread cascading outages due to overloads, instability, or voltage collapse, or the inability to meet the **Nuclear Plant Interface Requirements (NPIRs)**. The NPIRs for each nuclear plant generator subject to dispatch by ISO New England Inc. (ISO) are documented in its ISO Form NX-12 under ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Resources and Asset Related

Demands. The loss of small portions of the system may be tolerated provided the reliability of the overall interconnected system is not jeopardized and the **NPIRs** are met.

The standards outlined hereinafter are not tailored to fit any one system or combination of systems but rather outline a set of guidelines for system design which will result in the achievement of the desired level of reliability and efficiency for the New England **bulk power supply system**.

2. RESOURCE ADEQUACY

Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to **resource** deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.

a. The possibility that load forecasts may be exceeded as a result of weather variations.

b. Immature and mature **equivalent forced outage rates** appropriate for generating units of various sizes and types, recognizing partial and full outages.

c. Due allowance for scheduled outages and deratings.

d. Seasonal adjustment of **resource** capability.

e. Proper maintenance requirements.

f. Available operating procedures.

g. The reliability benefits of interconnections with systems that are not Governance Participants.

h. Such other factors as may from time-to-time be appropriate.

For planning purposes, the assumed **equivalent forced outage rate** of a generating unit connected to the transmission network by a radial transmission line will be increased to reflect the estimated transmission line forced outage rate if significant.

The potential power transfers from outside New England that are considered in determining the New

3. AREA TRANSMISSION REQUIREMENTS

The New England **bulk power supply system** shall be designed with sufficient transmission capacity to integrate all **resources** and serve **area** loads and meet the applicable **NPIRs** under the conditions noted in Sections 3.1 and 3.2. These requirements will also apply after any critical generator, transmission circuit, transformer, phase angle regulating transformer, HVDC pole, series or shunt compensating device has already been lost, assuming that the **area resources** and power flows are adjusted between outages, using all appropriate reserve **resources** available in ten minutes and where applicable, any phase angle regulator control, and HVDC control.

With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load, and **resource** conditions that reasonably stress the system. Transfers of power to and from another **Area**, as well as within New England, shall be considered in the design of inter-Area and intra-Area transmission facilities.

Transmission transfer capabilities will be based on the load and **resource** conditions expected to exist for the period under study and shall be determined in accordance with Section 4.1 for normal transfers, and Section 4.2 for **emergency** transfers. All reclosing facilities will be assumed in service unless it is known that such facilities have been or will be rendered inoperative.

In applying these criteria, it is recognized that it may be necessary to restrict the output of a generating station(s) and/or HVDC terminal(s) following the loss of a system **element**. This may be necessary to maintain system stability or to maintain line loadings within appropriate thermal ratings in the event of a subsequent outage. But, the system design must be such that, with all transmission facilities in service, all **resources** required for reliable and efficient system operation can be dispatched without unacceptable restriction.

Special Protection Systems (SPSs) may be employed in the design of the interconnected power system. All SPSs proposed for use on the New England system must be reviewed by the Reliability Committee and NPCC and approved by the ISO. Some SPSs may also require acceptance by NPCC. The requirements for the design of SPSs are defined in the NPCC "Bulk Power System Protection Criteria" and the NPCC "Special Protection System Criteria". A set of guidelines for application of SPSs on the New England system are contained in the ISO New England Planning Procedure 5-6 “Special Protection Systems Application Guidelines”.

3.1 STABILITY ASSESSMENT

a. Adequate reactive power resources with reserves and appropriate controls shall be installed to maintain voltages within normal limits for pre-disturbance conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in Section 3.1.

b. Line and equipment loadings shall be within normal limits for pre-disturbance conditions and within **applicable emergency limits** for the system load and generation conditions that exist following the **contingencies** specified in Section 3.1.

3.3 FAULT CURRENT ASSESSMENT

The New **England bulk power supply system** shall be designed to ensure equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all potential operating conditions.

4. TRANSMISSION TRANSFER CAPABILITY

The New England **bulk power supply system** shall be designed with adequate inter-Area and intra-Area transmission transfer capability to minimize system reserve requirements, facilitate transfers, provide **emergency** backup of supply **resources**, permit economic interchange of power, and to assure that the conditions specified in Sections 3.1 and 3.2 can be sustained without adversely affecting the New England system or other **Areas** and without violating the **NPIRs**. Anticipated transfers of power from one **area** to another, as well as within **areas**, should be considered in the design of inter-Area and intra-Area transmission facilities. Therefore, design studies will assume applicable transfers and the most severe load and **resource** conditions that can be reasonably expected.

Firm transmission transfer capabilities shall be determined for Normal and **Emergency** transfer conditions as defined in Sections 4.1 and 4.2. Normal transfer conditions are to be assumed except during an **Emergency** as defined by Item 7 in Appendix A. In determining the **emergency** transfer capabilities, a less conservative margin is justified.

4.1 NORMAL TRANSFERS

For normal transfer conditions the New England **bulk power supply system** shall remain stable and damped in accordance with the criterion specified in Appendix C in during and following the most severe of the conditions specified in Section 3.1 "a" through "h", **with due regard to reclosing**, and before making any manual system adjustments.

Voltages, line loadings and equipment loadings shall be within normal limits for pre-disturbance conditions and within **applicable emergency limits** for the system load and **resource** conditions

Document History[2]

Rev. 0 Rec.: RTPC - 6/8/99; App.: NEC - 7/9/99
Rev. 1 Rec.: RC - 12/7/04; App.: PC - 1/7/05
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Rev. 5 Modifications Only Address NERC Standard NUC-001-2
Rec.: RC – xxxxxx; Rec. PC – xxxxxx; Eff. xxxxxx

[2] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

APPENDIX "A"

LIST OF DEFINITIONS

1. **APPLICABLE EMERGENCY LIMIT**

——These **emergency** limits depend on the duration of the occurrence, and are subject to New England standards.

——**Emergency** limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

——The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, meet the **Nuclear Plant Interface Requirements** and should not adversely affect the operation of the New England **bulk power supply system**.

——The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities.

2. **AREA**

——An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system.

3. **BULK POWER SUPPLY SYSTEM**

——The New England interconnected bulk power supply system is comprised of generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local **area**.

4. **CONTINGENCY** (as defined in NPCC Document A-7)

——An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.

5. **DELAYED FAULT CLEARING** (as defined in NPCC Document A-7)

——Fault clearing consistent with correct operation of a breaker failure **protection group** and

its associated breakers, or of a backup **protection group** with an intentional time delay.

6. **ELEMENT** (as defined in NPCC Document A-7)
——Any electric device with terminals which may be connected to other electric devices, usually limited to a generator, transformer, circuit, circuit breaker, or bus section.

7. **EMERGENCY**
——An emergency is considered to exist if firm load may have to be reduced because sufficient capacity or energy is unavailable after due allowance for purchases. Emergency transfers are applicable under such conditions. The emergency is considered to exist as long as any firm system load is potentially or actually curtailed.

8. **EQUIVALENT FORCED OUTAGE RATE**
——The equivalent forced outage rate (EFOR) is the ratio of total time a generator is completely forced out of service plus the equivalent full outage time of any forced partial restrictions, to the total time that the unit is not on scheduled maintenance.

9. **HVDC SYSTEM, DIRECT CURRENT BIPOLAR**
——An HVDC system with two poles of opposite polarity.

10. **NORMAL FAULT CLEARING** (as defined in NPCC Document A-7)
——Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**~~.~~

11. **NUCLEAR PLANT INTERFACE REQUIREMENTS** (as defined in the NERC Glossary of Terms Used in Reliability Standards and as documented in ISO Form NX12)

12. **PROTECTION GROUP** (as defined in NPCC Document A-7)
A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

~~(a)~~a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

ISO NEW ENGLAND PLANNING PROCEDURE 5-1

PROCEDURE FOR REVIEW OF GOVERNANCE PARTICIPANT'S PROPOSED PLANS (SECTION I.3.9 APPLICATIONS: REQUIREMENTS, PROCEDURES AND FORMS)

EFFECTIVE DATE: ~~June 5, 2009~~January 11, 2010 Draft

REFERENCES: ISO New England Transmission, Markets and Services Tariff

ISO NEW ENGLAND PLANNING PROCEDURE NO. 5-1

PROCEDURE FOR REVIEW OF GOVERNANCE PARTICIPANT'S PLANS
(SECTION I.3.9 APPLICATIONS: **REQUIREMENTS, PROCEDURES AND FORMS)**

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Attachment 3 TRANSMISSION FACILITIES PROPOSED PLAN APPLICATION
Attachment 4 ISO NEW ENGLAND GENERATOR NOTIFICATION FORM FOR UNITS OR CHANGES OF LESS THAN 5 MW
Attachment 5 PROPOSED PLAN APPLICATION SUBMITTAL PROCEDURE

committee may elect to defer action subject to the time constraints defined in Section 1.3.

If in reviewing the application and associated information, the Reliability Committee decides additional information, review, or study is required prior to acting on the application, the Reliability Committee may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the Governance Participant sponsoring the application, other Governance Participants, the ISO, the Task Forces, or other committees.

The actions the Reliability Committee may take are to defer action, recommend approval by the ISO, or recommend disapproval by the ISO. The Reliability Committee is expected to act on all Proposed Plan Applications that require Level II or Level III analysis. Applications requiring Level I analysis do not need approval, but do need Reliability Committee concurrence that only Level I analysis is required.

Reliability Committee members[1] will be responsible for establishing an understanding of each application through ~~their own knowledge,~~ review of the documentation provided with the application~~,~~ and/or consultation with the ISO, the task forces[2], and/or subcommittees.

The Secretary of the Reliability Committee will notify the Members and Alternates of the Participants Committee and the ISO of the actions taken by the Reliability Committee. This written notice will be delivered prior to the end of the fifth (5^{th}) business day following a meeting of the Reliability Committee as specified by the Technical Committee Bylaws. This notification will constitute formal confirmation that such action was taken. The ISO will consider the recommendations of the Reliability Committee in the process of approving/disapproving each Proposed Plan Application. The ISO will transmit an official letter to the Governance Participant submitting the Application noting such approval or disapproval. Upon approval the Governance Participant shall be free to implement the proposed plan in accordance with the Tariff, including compliance with any additional requirements contained therein, .e.g. the requirements of the process for the interconnection of new generating resources or modification of existing generating resources pursuant to Schedules 22 and 23 of

[1] Governance Participants, including Nuclear Plant Generator Operators seeking to meet their Nuclear Plant Interface Requirements, will be informed of proposed changes to the New England system through their Reliability Committee representative(s).

[2] Reliability Committee members may, upon request, be included in any task force distribution list or review the task force meeting agendas, which are posted on the ISO website, and attend any task force meeting after providing a notice to an officer of that task force, to consult with the ISO and/or the task forces regarding the documentation of any forthcoming application that is being reviewed by any task force.

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GENERATION PROPOSED PLAN APPLICATION
(Effective until May 31, 2010)

Applicant _____ Date_____.

Contact Person _____ Phone # _____.

1. Station Name and Location _____.

   Unit Identification _____.

	Winter (0 Deg F)*	Winter (20 Deg F)	Summer (50 Deg F)**	Summer (90 Deg F)
Gross Unit Rating (MW)				
Net Unit Rating (MW)				
Unit Rating (Lagging MVAR)		N/A		
Unit Rating (Leading MVAR)		N/A		

* Maximum gross unit rating must be at 0 degrees F or greater.

** Maximum net unit rating must be at 50 degrees F or greater.

2. Type of Application
   □ Construction □ Capacity Change □ Deactivated Reserve □ Retirement □ Reactivation

3. Effective Date _____.

IF THIS IS FOR RETIREMENT OR DEACTIVATION, SKIP TO #13.

4. Will the unit be equipped for AGC? □ Yes □ No
   a. What is the unit's low operating limit based on its physical characteristics?
   b. Does the unit have an operating range of 25MW or more? □ Yes □ No
   c. Does the unit have a response rate of ≥ 1MW/Min? □ Yes □ No

5. Will the unit be equipped with a functioning governor? □ Yes □ No (A "No" response may be grounds for rejection pursuant to OP 14 “Technical Requirements for Generators, Demand Resources and Asset Related Demands”.)

6. Is the unit equipped with under-frequency protection? □ Yes □ No
   If "yes":
   a. Has the host utility reviewed the settings? □ Yes □ No

   b. Will the unit be tripped for under-frequency conditions in the area above the curve in Figure 1 of NPCC ~~Document A-3~~Regional Reliability Reference Directory # 12? □ Yes □ No

   c. Will the unit be tripped in conjunction with dropping low voltage feeders during load shedding?

   d. If "Yes" to b or c: Has additional automatic load shedding been provided equivalent to the amount of generation to be tripped? □ Yes □ No
   If "Yes", describe using an attachment.

Note: A "No" response to d. is grounds for rejection. A “Yes” response to b. or c. has an on-going obligation to report this information to the ISO. A “No” response to a. will obligate the Governance Participant to complete this review prior to interconnection of the facility.

ISO NEW ENGLAND PLANNING PROCEDURE 5-3

GUIDELINES FOR CONDUCTING AND EVALUATING PROPOSED PLAN APPLICATION ANALYSES

EFFECTIVE DATE: ~~February 1, 2005~~January 25, 2010 Draft

3.1.3.2.5 Conclusions
Present arguments for approval of application consistent with Section 3.3.3 for steady state analyses, Section 3.5.3 for stability analyses and Section 3.4 for other testing.

3.2 Evaluation

The Reliability Committee and its Task Forces will evaluate a number of aspects of the studies submitted in support of a Proposed Plan Application. The evaluation of the acceptability of the proposed changes or additions begins with review of the adequacy and acceptability of testing and test results. The results of tests performed and submitted in support of proposed additions or changes in facilities should clearly demonstrate compliance with the desired level of reliability as outlined in the Reliability Standards. The level of performance expected is intended to: 1) assure the reliability of the overall interconnected system and minimize the risk of widespread cascading outages due to overloads, instability or voltage collapse; and 2) demonstrate that the Nuclear Plant Interface Requirements (NPIRs) as documented in ISO Form NX-12 are met. Sections 3, 4 and 5 of the Reliability Standards establish a minimum design criteria by outlining representative contingency tests and assessment.

Demonstration of acceptable system performance under the enumerated conditions and assumptions should be considered the minimum level of compliance. Additional testing, evaluations or adjustments to assumptions may be deemed necessary to either assure the adequacy of system performance or to distinguish a sensitivity to one particular condition from a more general system weakness. The final conclusions and recommendations should be based on the informed engineering judgment of the Reliability Committee and its Task Forces with the objective of assuring that proposed changes or additions in facilities will not have a significant adverse impact on the stability, reliability or operating characteristics of the interconnected bulk power system.

Generally, if results of testing indicate that the system is not sufficient to accommodate the proposed changes or additions in facilities, system reinforcements or other mitigating measures will be required. These reinforcements or mitigating measures should fully alleviate all adverse impacts which were introduced by the proposed change or addition.

Occasionally, testing may identify weaknesses in the system prior to introduction of the proposed change or addition in facilities. The degree to which the proposed change or addition further degrades the stability, reliability or operating characteristics of the system will be of primary concern. Where no significant impact is identified, it may be possible to conclude that the proposed change or addition does not degrade system reliability. This judgment should take into account the frequency, duration, magnitude and consequences of any conditions where reliability violations occur both prior to and subsequent to the proposed changes or additions.

3.3 Steady State Analysis

3.3.2.1 Summary of load flow tests conducted and their results, with and without the proposed modifications, showing at a minimum the following information:
- Load level, generation dispatch and pertinent major interface loadings (both inter-Area and intra-Area);
- Contingencies tested;
- A single summary of lines loaded to 95% or more of their applicable rating;
- Bus voltages outside a range of .95 to 1.05 p.u.;
- Interactions with existing special protection systems; and
- Observed results and related comments, including impact on NPIRs, as appropriate.

3.3.2.2 Summary of results from any other pertinent testing performed such as the analyses described in Section 3.4, Other Testing.

3.3.2.3 One line diagrams showing flows and voltages with and without the proposed changes or additions for the following conditions:
- Normal generation dispatch conditions with all lines in service;
- Stressed generation dispatch conditions with all lines in service; and
- All significant contingency conditions for both normal and stressed generation dispatch cases.

3.3.2.4 Clear, concise narrative interpreting the above results and leading to the conclusion that installation of the subject facility(ies) will have no significant adverse effect on the reliability of the bulk power system as specified in Section I.3.9 of the Tariff. Also, any actions required to mitigate adverse system behavior associated with the proposed facility should be fully documented and explained.

3.3.3 Steady State Evaluations

Evaluations of steady state analyses submitted in support of Proposed Plan Applications will be based on the considerations and expectations described in Section 3.2, Evaluation. Additionally, the two aspects noted below will be of primary concern to the Reliability Committee and its Task Forces during their review.

3.3.3.1 Was the analysis conducted according to generally accepted practice?
- Were assumptions and test conditions as outlined in Section 3.3.1?
- Were tools and procedures applied properly and were they sufficient to provide a complete analysis?

3.3.3.2 Do results of the analysis support the conclusion that the change(s) will: 1) result in no significant adverse effect on the reliability of the bulk power system; and 2) meet the NPIRs? If the analyses indicated any problem areas, how were they resolved?

In particular, the Transmission Task Force will review each analysis to ensure that all of the applicable conditions specified in the Reliability Standards are satisfied. The recommendation of the Transmission Task Force to the Reliability Committee will be based on the applicant having satisfied the applicable conditions required in the Reliability Standards.

3.4 Other Testing

Studies demonstrating system performance may occasionally require other testing, in addition to the load flow testing described in Section 3.3 above, to adequately assess the effects of proposed facility changes or additions on the reliability and operating characteristics of the bulk power system. The need for this other testing, such as transient network analysis, short-circuit analysis, and/or reactive power and voltage (Q/V) analysis, depends on the specific project involved. These three analyses, while dealing with dynamic phenomena, do not involve the detailed time simulation of a stability analysis; rather, each is a single snapshot of the ability of the power system to withstand events such as loss of components, short-circuits or unanticipated demand. It is the responsibility of the Governance Participant submitting the Proposed Plan Application to consider the need for these tests when preparing the Proposed Plan supporting analysis and include them as appropriate. The Reliability Committee, its Task Forces, or individual Governance Participants may request any one or more of these other tests or in the course of their review of the supporting analysis may request other testing not described in this guideline. Each Governance Participant that is a Nuclear Plant Generator Operator is expected to have its Reliability Committee representative review the reporting of analysis of a proposed plan and request any additional analysis to address meeting any applicable NPIRs.

3.4.1 Transient Network Analysis (TNA)

Transient Network Analysis studies are typically performed as part of the detailed design engineering of a project where there may be concern for transient or temporary overvoltages, voltage flicker, arrester capabilities or insulation coordination. Sudden changes in circuit conditions, such as switching operations, lightning strikes, sudden loss of load or inrush currents (e.g., from a cable, capacitor bank or transformer energization or de-energization) can lead to this type of overvoltage, whose effects are usually confined to an area localized to the switching station. As such, those projects where this would be a concern typically include a TNA study as part of the design process but do not usually include the TNA results as part of the Proposed Plan study.

In those situations where a neighboring Governance Participant is close enough to be affected (typically no more than two busses away from the switching location), the applicant and the other Governance Participant should engage in a joint review of the base case models to be used in the TNA study. Then, in the Proposed Plan study, the applicant should provide sufficient details and information to clearly demonstrate system performance under both normal and stressed conditions. This would normally include a summary of all TNA tests conducted and their results, generally in the form of peak overvoltages or percent voltage change at selected busses and a clear, concise narrative interpreting these results and leading to the conclusion that installation of the subject

3.5.3.1 Was analysis conducted according to generally accepted practice?
- Were assumptions and test conditions as outlined in Section 3.5.1?
- Were tools and procedures applied properly and were they sufficient to provide a complete analysis?

3.5.3.2 Do results of analysis support conclusion that the change(s) will: 1) result in no significant adverse effect on the reliability of the bulk power system; and 2) meet the NPIRs? If the analyses indicated any problem areas, how were they resolved?

The Stability Task Force will review each analysis to ensure that all of the applicable conditions in the Reliability Standards are satisfied. The recommendation of the Stability Task Force to the Reliability Committee will be based on the applicant having satisfied the applicable conditions required in the Reliability Standards.

4.0 Protection Systems and Dynamic Control Systems

Sections 2.6 and 3.3 of PP5-1 indicate the protection system additions/changes for which Proposed Plan Applications are required. These fall into two categories: fault clearing and special protection systems (SPSs).

Proposed Plan Applications for additions/changes in protection systems designed for fault clearing should include assurance that:
- the protection system is designed in accordance with the NPCC Bulk Power System Protection Criteria; and
- the associated fault clearing time will not degrade system reliability performance; and
- the NPIRs will be met.

A Level III analysis, as described in Section 3.0, may be needed to demonstrate the effects of increased fault clearing times.

Applications for SPSs require analyses similar to that of a generation or transmission application and the guidelines of Section 3.0 apply. In addition to compliance with the Reliability Standards and NPCC Bulk Power System Protection Criteria, the following factors will be considered in evaluating an application for an SPS:
- Is the SPS initiated by a normal contingency or an extreme contingency?
- How many events trigger the SPS? Are the triggers local or remote?
- What are the monitoring requirements?
- How selective are the triggers (i.e., monitor system parameters vs. breaker contact)?
- Is the response local or remote?
- How many inputs, decisions and actions are involved?
- What is potential for interaction with other SPSs?
- Is the SPS required to control dynamic, voltage or thermal response?
- What actions are taken (load rejection, generation rejection, opening of a transmission line)?
- What is the probability that the SPS will be required to operate?
- What are the implications of inadvertent operation or misoperation (local vs. widespread effects)?

- Operational considerations (operator's view of requirements and constraints).
- Anticipated life of the SPS - is it meant to be temporary or permanent?
- What operating options are available if planning assumptions do not materialize?
- What are modeling requirements; when will they be provided?
- Economic tradeoffs with other alternatives.
- Will the NPIRs be met?

Dynamic control systems such as voltage regulator/exciter systems, power system stabilizers and governors on generators can have a significant effect on the stability, reliability or operating characteristics of the bulk power system. Such dynamic control systems and their attendant effects are to be included in the analyses conducted in support of new generator additions. Effects of changes in dynamic control systems should normally be determined in the course of design studies and a Proposed Plan Application should be submitted if such a change could have a significant effect on the performance of the bulk power system. In such cases, a stability analysis may be requested as outlined in Section 3.5.

5.0 Definitions

If appropriate definitions were available from the Reliability Standards they are used in this section. The source of the definition is shown in parenthesis. Following these existing definitions, additional comments are included to assist the reader in interpreting them.

For those cases where no formal definition exists, the one used here is based on a review of existing ISO New England and NPCC documents.

5.1 Applicable Emergency Limit ~~(Reliability Standards, Appendix A)~~

~~"These emergency limits depend on the duration of the occurrence, and is subject to ISO New England standards.~~

~~Emergency limits are those which can be utilized for the time required to take corrective action but in no case less than five minutes.~~

~~The limiting conditions for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the bulk power system.~~

~~The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices upon the failure of facilities."~~

Transmission circuit loading limits have been established for use under both normal and emergency conditions. In general, normal ratings are used for "All lines in" conditions. Under emergency conditions, long term emergency ratings (LTE) may be used for up to one daily load cycle assuming no contingency would cause the loading to go above LTE. Short term emergency ratings (STE) may be used following a system disturbance for up to fifteen minutes.

The STE ratings may only be used in situations where the component loading can be reduced below the LTE ratings within fifteen minutes by operator corrective action.

In actual system operations, under emergency conditions, drastic action limits (DAL) may be used where preplanned immediate post contingency actions can reduce loadings below LTE within five minutes. These DAL limits are only used as a last resort during actual system operations. They should not be used in testing the system adequacy in the Proposed Plan Application studies.

Emergency voltage limits have also been established for system operation under emergency conditions. These limits recognize that voltages should not drop below those voltages required for acceptable system stability performance, acceptable operation of generating auxiliaries, acceptable operation of other electrical equipment, ~~and~~ operation well above the knee of the voltage curve, and for meeting the NPIRs. Also, the voltage should not rise above the maximum rating of electrical equipment.

5.2 Reasonably Stressed Conditions

Reasonably stressed conditions are those severe load and generation system conditions which have a reasonable probability of actually occurring. Generally both import and export conditions should be addressed. The purpose of testing these conditions is to identify potential weaknesses in the system and not to test the worst imaginable extreme.

5.3 Operating Characteristics

The actual operation of the interconnected system requires that each component of the system must be capable of operating in such a manner as not to adversely affect the system operation. Any additions to the system must be able to operate in such a manner so as not to degrade the present operating flexibility of the system. Operating Characteristics include, but are not limited to: dispatchability, including constraints on economic dispatch, voltage control, flicker, harmonics, black start capability, environmental limitations, maintenance scheduling, TV and radio interference, audible noise, and under frequency load shedding.

5.4 Significant Adverse Effect (Section I.3.9 of the Tariff)

The existing system is designed and operated to meet specific criteria as contained in the various documents referenced through this guideline. After the addition it must be demonstrated that there has been no significant degradation in the level of system performance.

5.5 Normal Dispatch Conditions

Normal Dispatch Conditions refers to the economic dispatch of all New England Control Area generation with appropriate allowance for scheduled maintenance and forced outages. Applicable firm contractual transfers, both purchases and sales, should be included.

5.6 Special Protection Systems (Reliability Standards, Appendix A)

"A Special Protection System (SPS) is defined as a protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, resource, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic under frequency load shedding, as defined in NPCC Emergency Operation Criteria A-3, is not considered an SPS."

Document History[1]

Rev. 0 Rec.: RTPC – 1/18/00; App.: PC – 2/4/00
Rev. 1 Rec.: RC – 11/14/00; App.: PC 12/1/00
Rev. 2 Eff.: 2/1/05
Rev. 3 Rec. RC – x/xx/10; Rec.: PC x/xx/10; Eff.: x/xx/10

[1] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

M E M O R A N D U M

TO: Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: February 26, 2010

RE: Amendment to Section 12.9 of Market Rule 1 in Compliance with the FERC February 12, 2010 Order on Jump Ball Filing re: 3rd ARAs

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On February 12, 2010 the Federal Energy Regulatory Commission (the "Commission") issued an order (the "February 12 Order", included with this memo) in the so-called "Jump Ball" proceeding regarding alternative amendments to Section 12.9 of Market Rule 1 (Docket No. ER10-438-000). The February 12 Order was described in a memo from NEPOOL counsel sent to you on February 15 and is included for your convenience with this memo.

One compliance requirement came out of the February 12 Order. That requirement directed the inclusion of language in Section 12.9 of Market Rule 1 along the following lines:

> [B]y December 31, 2010, the ISO shall review with Market Participants and, as necessary, file proposed market rule amendments reflecting a methodology for tie benefit calculations to apply to future third annual reconfiguration auctions beginning with the third annual reconfiguration auction for the 2012/2013 Capacity Commitment Period.[1]

An amendment to Market Rule 1 to respond to this requirement must be filed by March 12, 2010. At its February 26 meeting, the Reliability Committee voted unanimously to recommend Participants Committee support for that amendment (a copy of which is included with this memorandum).

The following form of resolution could be used for Participants Committee action on this item:

> RESOLVED, that the Participants Committee supports the proposed amendment to Section 12.9 of Market Rule 1 in response to the requirements of the February 12 order in FERC Docket No. ER10-438, [as recommended by the Reliability Committee and] as distributed to the Participants Committee for its March 5, 2010 meeting.

[1] February 12 Order at P 79.

memo

To: NEPOOL Reliability Committee

From: Mark Karl, Senior Director of Resource Adequacy

Date: February 18, 2010

Subject: Revision to Market Rule 1, Section 12.9 for Compliance with Commission Order in Docket No. ER10-438

On December 15, 2009, the ISO and NEPOOL presented the Federal Energy Regulatory Commission (the "Commission") with alternative amendments to Section III.12.9 of Market Rule 1 on the calculation of tie benefits for annual reconfiguration auctions. These amendments were presented as part of the filing of the ICR values for the 2010/2011 third annual reconfiguration auction. In filing its proposed tariff amendment, NEPOOL asserted that the amendment was subject to the "Jump Ball" provision in the Participants Agreement. On February 12, 2010, the Commission issued an order in the proceeding. Agreeing with NEPOOL on the application of the Jump Ball provision to its amendment, the Commission ruled that the ISO's proposed tariff amendment is just and reasonable and preferable to the NEPOOL proposed amendment (which is the standard that applies under the Jump Ball provision). However, the Commission directed the ISO to amend Section III.12.9 of Market Rule 1 to reflect the ISO's commitment to hold a stakeholder process in 2010 to address outstanding issues pertaining to the calculation of tie benefits for the third annual reconfiguration auction. The February 12 order requires that a filing to reflect this amendment be made with the Commission within 30 days of the order.

In directing the ISO to file the tariff amendment, the Commission quoted the following excerpt from NEPOOL's proposed amendment and ordered the ISO "to revise section III.12.9 of Market Rule 1, consistent with the language and timeline proffered by NEPOOL."[1]

> [B]y December 31, 2010, the ISO shall review with Market Participants and, as necessary, file proposed market rule amendments reflecting a methodology for tie benefit calculations to apply to future third annual reconfiguration auctions beginning with the third annual reconfiguration auction for the 2012/2013 Capacity Commitment Period.[2]

Accordingly, the ISO is proposing to modify Section III.12.9 of Market Rule 1 to incorporate this language.

In order to meet the 30-day compliance obligation, the ISO is requesting that the Reliability Committee vote at its February 26, 2010 meeting to recommend the proposed revision to the Participants Committee, and will request Participants Committee support for the revision at its March meeting.

Please feel free to contact me with any questions at mkarl@iso-ne.com.

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[1] February 12 Order at P 80.
[2] February 12 Order at P 79.

ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com **T** 413 535 4000

M E M O R A N D U M

TO: Reliability Committee (with copy to Participants Committee)

FROM: Eric Runge, NEPOOL Counsel

DATE: February 15, 2010

RE: FERC February 12, 2010 Order on Jump Ball Filing re: 3rd ARAs

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On February 12, 2010 the Federal Energy Regulatory Commission (the "Commission") issued an order (the "February 12 Order", included with this memo) in the so-called "Jump Ball" proceeding regarding alternative amendments to Section 12.9 of Market Rule 1 (Docket No. ER10-438-000). In the Jump Ball proceeding ISO New England Inc. ("ISO-NE") and NEPOOL proposed alternative amendments to Section 12.9 regarding how to calculate tie benefits for third annual reconfiguration auctions. ISO-NE proposed to use the at-criteria value derived for the primary auction in each subsequent reconfiguration auction (resulting in a tie benefit value of 1,860 MW for the 3rd ARA for the 2010/2011 Capacity Commitment Period, with no language to provide a sunset for that provision or require the development of a new method. NEPOOL proposed using the current as-is method of calculating tie benefits for the third ARAs but with a cap of 2,286 MW for 2010/2011 and 2011/2012 and with a sunset and a requirement for a NEPOOL stakeholder process to be concluded by the end of 2010 to develop new rules for 3rd ARAs commencing with the 2012/2013 Capacity Commitment Period.

Aside from choosing between the alternative amendments, the other main issue before the Commission in this proceeding was the applicability of the Jump Ball provision (Section 11.1.5 of the Participants Agreement) to Market Rule amendments pertaining to the determination of ICR values. ISO-NE took the position that the Jump Ball provision was not applicable; NEPOOL argued that the Jump Ball provision was applicable.

The February 12 Order

1. Jump Ball Applicability

As a threshold matter the Commission agreed with NEPOOL that the Jump Ball provision applied to the NEPOOL alternative amendment, because the amendment was an amendment to a "Market Rule" (as defined in the Participants Agreement) and because it had the requisite NEPOOL support (60% or better). In P 57 the Commission states in part:

> ISO-NE determines and files Installed Capacity Requirements—the values—under section 11.4 . The methodology for calculating those values, however, is part of the Market Rules and, as such, any proposed amendment to the methodology comes under the provisions of section 11.1. Read within the full context of section 11 and its individual subparts, we find that the proposals at

> issue here involve changes to the methodology for calculating the Installed Capacity Requirements, not the values, and thus fall within the scope of section 11.1, which includes the jump ball provision, rather than section 11.4.

Thus, the Commission's order should remove any doubt that the Jump Ball provision of the Participants Agreement applies to all NEPOOL alternative Market Rule amendments, including those related to ICR, that have 60% or greater support by NEPOOL.

2. The Alternative Amendments

The February 12 Order adopts part of the ISO proposal and part of the NEPOOL proposal. The Commission accepted ISO-NE's proposal to use the at-criteria tie benefit value derived for the primary Forward Capacity Auction in subsequent reconfiguration auctions (which means that 1,860 MW is the tie benefit value for the 2010/2011 Capacity Commitment Period). The Commission declined to use the NEPOOL proposal of keeping the as-is calculation with a temporary cap of 2,286 MW of tie benefits (on the grounds that there was insufficient analysis to support it—see esp., PP 84-88). Although the Commission accepted the ISO's proposal, it did so with a 30-day compliance condition that ISO amend the proposal to adopt the NEPOOL sunset provisions. At P 88 the February 12 Order states: "Further, as discussed above, we are directing ISO-NE to implement NEPOOL's proposed two-year sunset provision such that ISO-NE must employ a stakeholder process to address revising the tie benefit methodology applicable to the third reconfiguration auction for the 2012/2013 commitment period." Thus, by March 12, 2010 ISO-NE must make a compliance filing modifying its proposal to include the following language in Section 12.9 of market Rule 1:

> [B]y December 31, 2010, the ISO shall review with Market Participants and, as necessary, file proposed market rule amendments reflecting a methodology for tie benefit calculations to apply to future third annual reconfiguration auctions beginning with the third annual reconfiguration auction for the 2012/2013 Capacity Commitment Period.[1]

3. Other

There are at least two other points of interest in the February 12 Order that should be noted. First, the Commission indicates that an alternative proposal that is otherwise justified from a reliability standpoint could be considered preferable if it is better from a cost perspective. The Order indicates that had NEPOOL been able to demonstrate a sound analytical basis for its 2,286 MW tie benefit cap it might have been chosen as preferable:

> In fact, if we were presented with two equally defendable tie benefits values, all other things being equal, we may find the higher tie benefits number to be "more" just and reasonable, as it would reduce the Installed Capacity Requirement,

[1] February 12 Order at P 79. This compliance amendment will need to go through the NEPOOL stakeholder process, with votes at the February 26, 2010 meeting of the Reliability Committee and the March 5, 2010 meeting of the Participants Committee.

> minimizing the purchase of "unnecessary capacity." It is the absence of such a scenario before us, however, that defines our decision to adopt ISO-NE's tie benefits value of 1,860 MW, as opposed to NEPOOL's proposed value of 2,286 MW, for the 2010/2011 commitment period.[2]

Second, the February 12 Order indicates that the Commission wants ISO-NE to help stakeholders in doing the analysis required to support alternative proposals, and requires ISO-NE to consider a process for doing so: "For periods going forward, we are directing ISO-NE to consider a process to enable analysis of alternative proposals in a future market rule amendment."[3]

Under FERC rules, any request for rehearing or clarification of this order would need to be filed on or before March 12, 2010. At this time, we have not identified any aspect of the February 12 Order on which we would recommend that NEPOOL seek rehearing or clarification; however, we would welcome your thoughts, input and insights if you think NEPOOL should be doing so.

If you have questions about the February 12 Order or this memo, please contact Eric Runge at: (617) 345-4735, ekrunge@daypitney.com.

[2] *Id.* at P 74.

[3] *Id.* at p 88. See also P 81, which provides in pertinent part: "The [2010] stakeholder process in this regard also should address the contention raised by NESCOE and other commenters that ISO-NE failed to provide the analysis requested by some stakeholders in connection with alternative proposals, with detailed explanations of reliability needs, estimated emergency events, and cost implications of options."

130 FERC ¶ 61,105
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
and John R. Norris.

ISO New England Inc. and
New England Power Pool

Docket No. ER10-438-000

ORDER ACCEPTING ISO NEW ENGLAND'S PROPOSED INSTALLED CAPACITY REQUIREMENT, HYDRO QUEBEC INTERCONNECTION CAPABILITY CREDITS, RELATED VALUES, AND TARIFF CHANGES, SUBJECT TO CONDITION

(Issued February 12, 2010)

1. On December 15, 2009,[1] ISO New England Inc. (ISO-NE) and New England Power Pool (NEPOOL) jointly filed, pursuant to section 205 of the Federal Power Act (FPA), proposed values for the Installed Capacity Requirement and related values for use in the final Forward Capacity Market (FCM) reconfiguration auction for the 2010/2011 Capability Year to be held in March 2010. ISO-NE and NEPOOL also individually filed proposed amendments to Market Rule 1, section III.12.9 of ISO-NE's Transmission, Markets and Services Tariff (Tariff), pursuant to FPA section 205 and section 11.1.5 of the Participants Agreement, which permits submission of an alternative proposal in limited circumstances.[2] As discussed below, after reviewing ISO-NE's proposed Installed Capacity Requirement and related values and both proposed amendments, we will accept the submitted Installed Capacity Requirement and related values and ISO-NE's proposed tariff changes, subject to condition, effective February 15, 2010, as requested.

[1] On January 5, 2010, ISO-NE filed an erratum to its December 15, 2009 filing, correcting minor grammatical and citation errors.

[2] Section 11.1.5 of the Participants Agreement provides for Commission review under section 205 of the FPA of an alternative Market Rule proposal that is approved by the Participants Committee by a vote equal to or greater than 60 percent.

I. Background and Summary of Joint Filing

2. As part of the FCM, ISO-NE is preparing to conduct the third and final annual reconfiguration auction for the 2010/2011 Capability Year.[3] ISO-NE conducts these annual reconfiguration auctions in the run-up to the delivery period for capacity to provide a more accurate depiction of the Installed Capacity Requirement needed for the ISO-NE control area during the Capability Year. In this proceeding, ISO-NE and NEPOOL jointly submitted the 2010/2011 Capability Year values for the Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit, all of which are key inputs in the Forward Capacity Auction (FCA). ISO-NE and NEPOOL also submitted the proposed value for Hydro Québec (HQ) Interconnection Capability Credits, which is a key input in the calculation of the Installed Capacity Requirement.

3. Further, ISO-NE and NEPOOL each proffered a limited proposed change to the existing Market Rules for calculating tie benefits that have a direct impact on the Installed Capacity Requirement. NEPOOL submitted its alternative proposal pursuant to section 11.1.5 of the Participants Agreement (Alternative Committee Market Rule Proposal), referred to as the "jump ball provision."[4] NEPOOL and ISO-NE disagree as to whether the jump ball provision applies in this case.

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[3] The 2010/2011 Capability Year extends from June 1, 2010, to May 31, 2011.

[4] Section 11.1.5 provides,

> If the Participants Committee vote relating to an ISO Market Rule proposal results in the approval by the Participants Committee by a Participants Vote equal to or greater than 60% of a Market Rule proposal that is different from the one proposed by ISO, including, but not limited to, a Governance Participant proposal, ISO shall, as part of any required Section 205 filing, describe the alternate Market Rule proposal in detail sufficient to permit reasonable review by the Commission, explain ISO-s reasons for not adopting the proposal, and provide an explanation as to why ISO believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission will not be required to consider whether the then-existing filed rate is unlawful, and may adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable.

(continued…)

A. Installed Capacity Requirement

4. The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England control area and to maintain sufficient reserve capacity to meet reliability standards. Specifically, the Installed Capacity Requirement is the amount of resources needed to meet the New England control area reliability requirements of disconnecting non-interruptible customers (i.e., the Loss of Load Expectation or LOLE) no more than once every ten years. The methodology for calculating the Installed Capacity Requirement is set forth in section III.12 of Market Rule 1.

5. Consistent with prior years' proposed Installed Capacity Requirement and related values, ISO-NE states that the values for this reconfiguration auction are based on three essential components: load forecast, unit availability, and tie benefits. Further, ISO-NE states that the methodologies for determining projected load and outage rates are consistent with those methodologies set forth in section III.12 of Market Rule 1. ISO-NE states that there was broad agreement among stakeholders regarding a majority of the assumptions, inputs, and calculations made to determine values for the third reconfiguration auction. ISO-NE states that there also was agreement that the tie benefits value was unacceptable under the methodology put forth in section III.12. ISO-NE explains that the limited disagreement between ISO-NE and NEPOOL is with regard to the methodology used for determining an appropriate tie benefit value for the 2010/2011 Capability Year.

1. Load Forecast

6. ISO-NE states that the forecasted peak loads of the entire New England control area for the 2010/2011 Capability Year were used to develop the corresponding annual Installed Capacity Requirement detailed in this filing. ISO-NE used the ten-year load forecast, covering the years 2009 through 2018, which was published in April 2009 in the ISO-NE's "2009-2018 Forecast Report of Capacity, Energy, Loads, and Transmission"

A "jump ball" is a term taken from basketball that describes how play is begun or resumed, in which two opposing players attempt to gain control of the ball that is tossed in the air in between them. *See* Nat'l Collegiate Athletic Ass'n 2009 Men's and Women's Basketball Rules, http://www.ncaapublications.com/Uploads/PDF/Basketball_Rules_2008-09fb2fc956-7592-4877-993e-dae20a6f90ed.pdf. The term is applied to the procedure described in section 11.1.5 to denote that alternate proposals are to be treated as co-equals, unlike the usual rate change application submitted under section 205 of the FPA.

(2009 CELT Forecast).[5] ISO-NE states that it developed the 2009 CELT Forecast using the same methodology used previously to develop Commission-approved Installed Capacity Requirement values,[6] reflecting economic and demographic assumptions as reviewed and supported by the NEPOOL Load Forecast Committee.

7. ISO-NE states that the projected New England control area 50/50 peak load (summer) for the 2010/2011 Capability Year is 28,160 megawatts (MW), which is 2.8 percent lower (795 MW) than forecasted in the April 2008 CELT Report.[7] The corresponding 90/10 peak load for the 2010/2011 Capability Year is 30,110 MW, which is 2.9 percent lower (905 MW) than forecasted in the April 2008 CELT Report.[8] ISO-NE states that the previous year's April 2008 CELT report used an economic forecast that predates the recession, whereas the April 2009 CELT Forecast used an economic forecast that included the current recession.[9]

2. Resource Capacity Ratings

8. ISO-NE states that the 2010/2011 Installed Capacity Requirement is based on ratings of capacity resources that have taken on capacity supply obligations for the 2010/2011 Capability Year and includes any megawatt proration of their obligations required under FCM rules. Additionally, the capacity value of Existing Demand Resources and New York Power Authority (i.e., NYPA) import contracts has been reduced by the amount of the reserve margin gross-up.[10] Similarly, no resource additions or attritions are assumed because there is no certainty that new resource additions or

[5] ISO-NE Transmittal Letter at 25 (citing CELT Forecasting Details 2009, *at* http://www.iso-ne.com/trans/celt/fsct_detail/index.html and CELT Report 2009, *at* http://www.iso-ne,com/trans/celt/report/index.html).

[6] ISO-NE Transmittal Letter at 25 (citing, e.g., *ISO New England Inc.*, 119 FERC ¶ 61,161 (2007) (accepting ISO-NE-proposed Installed Capacity Requirements for the 2007/2008 Power Year); *ISO New England Inc.*, 115 FERC ¶ 61,149 (2006) (accepting ISO-NE-proposed Installed Capacity Requirements for the 2006-2007 Power Year)).

[7] *See* ISO-NE Filing, Wong Test. at 15 and 23. The 50/50 peak load figure implies that this value has a 50 percent chance of being exceeded; a 90/10 peak load implies that this value has a 10 percent chance of being exceeded.

[8] ISO-NE Filing, Wong Test. at 15.

[9] ISO-NE Transmittal Letter at 25.

[10] ISO-NE Transmittal Letter at 26.

existing resource attritions will clear the auction.[11] ISO-NE states that the fact that it did not model resource additions or attritions will not have a significant effect on the Installed Capacity Requirement, since it is assumed that the availability characteristics and sizes of these resources will be similar to those of the Existing Resources.

3. Unit Availability

9. ISO-NE states that the proposed Installed Capacity Requirement for the 2010/2011 final annual reconfiguration auction uses different assumptions than those used for calculating the Installed Capacity Requirement for the previous annual reconfiguration auction; the numbers used for the final reconfiguration auction reflect updated outage data. ISO-NE maintains that the proposed Installed Capacity Requirement value reflects historical scheduled maintenance and forced outages of the capacity resources. ISO-NE states that the proposed 2010/2011 Installed Capacity Requirement reflects unit availability as measured by the Equivalent Demand Forced Outage Rate (i.e., EFORd) based on performance over the prior five-year period.[12] Individual generating unit maintenance assumptions are based on each unit's historical five-year average of scheduled maintenance or the North American Electric Reliability Corporation's (NERC) average scheduled maintenance data for the same class of unit, if five-year average data are not available. ISO-NE states that individual generating unit forced outage assumptions are based on the unit's historical forced outage data or NERC average data for the same class of unit. Performance assumptions for demand response resources are based on presumed or actual responses during all historical OP-4 (emergency) events and performance audits.[13]

4. Tie Benefits: ISO-NE Proposed Amendment

10. ISO-NE states that New England's Commission-approved method for establishing the Installed Capacity Requirement requires certain assumptions regarding the tie benefits value to be used. Specifically, ISO-NE explains that tie benefits from neighboring control areas reduce the Installed Capacity Requirement and, thus, the need to buy capacity within New England. The tie benefits from neighboring control areas reflect the

[11] ISO-NE Filing, Wong Test. at 17.

[12] The EFORd is the portion of time a unit is in demand but unavailable due to forced outages. *See* ISO-NE Tariff, § III.1.3.2 (hereinafter, Market Rule 1). Section III of the Tariff is Market Rule 1.

[13] ISO-NE Transmittal Letter at 27.

amount of emergency assistance that New England could rely on, without jeopardizing reliability in New England or its neighboring control areas, in the event of a capacity shortage in New England.

11. ISO-NE explains that tie benefits from neighboring control areas are used as an input assumption in the calculation of the Installed Capacity Requirement for the 2010/2011 Capability Year. ISO-NE states that under section III.12.9 of Market Rule 1, tie benefits for the initial FCA and the prior annual reconfiguration auctions were calculated using the "at criteria" method for purposes of modeling adjacent control areas. For the final reconfiguration auction, however, the market rules require that tie benefits be calculated using the "as is" methodology.

12. ISO-NE explains that the "as is" methodology assumes that neighboring control areas will have resources and demands equal to those that are forecasted for the time of the New England Capacity Commitment Period and that all those resources will be available to meet load within the neighboring control areas. ISO-NE further explains that, by contrast, the "at criteria" methodology assumes that neighboring control areas will have enough resources so that each area meets the reliability standard based on forecasted load for the capacity period. According to ISO-NE, the "at criteria" method lessens the impact of transient shortages and surpluses in the external control area. The reliability requirements for the New England control area are defined as disconnecting non-interruptible customers no more than once every ten years (0.1 LOLE).[14] ISO-NE states that the use of the "as is" methodology in the final reconfiguration auction (as required in the Tariff) makes theoretical and practical sense because of the close proximity of the auction to the relevant FCM Commitment Period. However, after calculating the tie benefits value for the third reconfiguration auction for the 2010/2011 Capability Year under the "as is" methodology, ISO-NE states that the resulting tie benefits and Installed Capacity Requirement values could have "serious, negative implications for reliability."[15]

13. ISO-NE states that using the "as is" methodology as prescribed in Market Rule 1 would result in a tie benefits value of 3,415 MW, resulting in an Installed Capacity Requirement of 30,988 MW for the third reconfiguration auction. Using the 3,415 MW value for tie benefits would reduce the New England reserve margin to 4.3 percent, reducing the resources available to ISO-NE in the case of an emergency.[16] ISO-NE notes

[14] ISO-NE Transmittal Letter at 9 (citing ISO-NE, 118 FERC ¶ 61,157, at P 44 (2007)).

[15] ISO-NE Transmittal Letter at 9-10.

[16] ISO-NE Filing, Brandien Test. at 4-5 and 10-11. The "reserve margin" is the percentage by which available capacity is expected to exceed forecasted peak demand.

that it would be very difficult to operate the New England electric system in accordance with NERC and Northeast Power Coordinating Council, Inc. (NPCC) reliability standards with a reserve margin of 4.3 percent. ISO-NE argues that reliance on this high value of tie benefits would jeopardize the reliable operation of the New England system, since this value is based on the assumption that 3,415 MW of emergency assistance is always available at a moment's notice to meet New England's needs.[17]

14. Since employing the "as is" methodology under the current market rules would result in tie benefits that would threaten the reliability of the ISO-NE system, ISO-NE proposes to use the tie benefit value calculated for the primary FCA for all annual reconfiguration auctions.[18] ISO-NE states that it has not taken the explicit stance that the "as is" methodology should be abandoned in favor of the "at criteria" methodology, since problems arising from the use of the "as is" methodology may also apply to the "at criteria" methodology.[19] However, ISO-NE believes that use of the "as is" methodology for the final reconfiguration auction would increase the possibility for reliability problems in the New England control area. Accordingly, for the upcoming annual reconfiguration auction, and until ISO-NE and its stakeholders are able to complete a more comprehensive stakeholder process on the use of the "as is" and "at criteria" calculation methodologies, ISO-NE proposes to change the market rules to maintain the use of the tie benefit value calculated for the primary FCA for all annual reconfiguration auctions.

15. ISO-NE proposes a tie benefits value of 1,860 MW, which is the value ISO-NE used in calculating the Installed Capacity Requirement and related values for the primary FCA and the previous annual reconfiguration auction for the 2010/2011 Capability Year. ISO-NE states that it does not believe that system conditions have changed sufficiently in neighboring control areas to warrant a departure from this previously used value.[20] ISO-NE further argues that using the 1,860 MW value will provide stability to the marketplace, ISO operators and operators in adjacent control areas.[21] ISO-NE states that providing a stable tie benefits value provides a degree of certainty when planning for performance during Capacity Commitment Periods. Additionally, it would allow ISO-NE to more efficiently use its resources since it would not be required to conduct

[17] ISO-NE Transmittal Letter at 13 (citing Karl Test. at 13).

[18] ISO-NE Transmittal Letter at 10.

[19] ISO-NE Transmittal Letter at 11.

[20] ISO-NE Transmittal Letter at 14-15 (citing Wong Test. at 29-30).

[21] ISO-NE Transmittal Letter at 15 (citing Karl Test. at 17).

multiple studies in the same year that provide similar results. Finally, the use of the 1,860 MW tie benefits figure would result in an Installed Capacity Requirement of 32,510 MW and an acceptable reserve margin of 9.7 percent.[22] ISO-NE notes that this reserve margin is still significantly lower than the reserve margins used in neighboring control areas, but it believes that the ISO-NE systems can reliably operate with a reserve margin of 9.7 percent for the 2010/2011 Capability Year.

16. ISO-NE also proposes to revise section III.12.9 of Market Rule 1 to require the use of the tie benefits value used for the primary FCA and previous annual reconfiguration auctions for the final annual reconfiguration auction.[23] ISO-NE asserts that its proposal is just and reasonable because (1) it would use a tie benefits value that has already been approved by the Commission, (2) it will provide stability to interested parties both inside the New England control area and neighboring control areas, and (3) it will allow for continued discussions between ISO-NE and New England stakeholders to determine any revised methodology for tie benefits in the future. Specifically, ISO-NE states that there are on-going discussions about the tie benefits methodology in related proceedings. ISO-NE notes that some of these issues (the Reserved Issues) have compliance obligations requiring a filing in February 2010. ISO-NE states that while progress has been made on them in isolation, given the remaining issues in play, the degree to which they are inter-related, and the probability that each is likely to be a contentious issue, it is proposing that all the remaining tie benefits issues be dealt with in a single process. ISO-NE plans to file the results of that process, including any revised tie benefits methodology, with the Commission by the end of 2010.

5. HQ Capability Credits

17. HQ Interconnection Capability Credits, also known as HQICCs, are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that hold certain rights over the HQ Interconnection. Because the new Commission-approved methodology for calculating HQICCs is not effective until the 2011/2012 Capability Year, ISO-NE states that it used the same HQICC assumptions as it had used to determine the Installed Capacity Requirement for the 2010/2011 primary FCA and second reconfiguration auction.[24] ISO-NE proposes to utilize HQICC values of

[22] ISO-NE Transmittal Letter at 15; 31,110 MW net of HQICCs.

[23] ISO-NE Transmittal Letter at 15; *see also id.* at 8-9.

[24] ISO-NE Transmittal Letter at 24. The Commission approved a new methodology for calculating HQICCs, but that change became effective with the primary FCA for the 2011/2012 Capability Year and, thus, will not be applied to calculations for the 2010/2011 Capability Year. *ISO New England Inc.*, 124 FERC ¶ 61,298 (2008).

1,400 MW for each month—July through November of 2010 and March through June of 2011—and zero (0) MW for the months of December 2010, and January and February 2011.

B. Local Sourcing Requirement and Maximum Capacity Limit

18. ISO-NE notes that, under the FCM, ISO-NE must calculate Local Sourcing Requirements and Maximum Capacity Limits to be used, if necessary, in each FCA. A Local Sourcing Requirement is "the minimum amount of capacity that must be electrically located within an import-constrained Load Zone"; a Maximum Capacity Limit is "the maximum amount of capacity that can be procured in an export-constrained Load Zone [to meet the Installed Capacity Requirement]."[25] ISO-NE notes that the general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to ensure that capacity resources are geographically distributed within the New England control area in a manner that helps to ensure that capacity is located where it is needed. ISO-NE states that for the 2010/2011 final reconfiguration auction, ISO-NE calculated the Local Sourcing Requirements for Connecticut and NEMA/Boston Load Zones as 6,496 MW and 1,838 MW, respectively;[26] and, the Maximum Capacity Limit for the Maine export-constrained Load Zone was calculated at 3,697 MW.[27] ISO-NE states that the Local Sourcing Requirements and the Maximum Capacity Limits were calculated using the same assumptions of forecasted load and resources as those used in the calculation of the Installed Capacity Requirement for the 2010/2011 final reconfiguration auction.

C. Proposed Values

19. ISO-NE and NEPOOL disagree on the value proposed for the Installed Capacity Requirement for the 2010/2011 Capability Year because of their different proposed tie benefits values. Using a tie benefits value of 1,860 MW (as calculated in previous reconfiguration auctions under the "at criteria" methodology) and deducting the HQICC value of 1,400 MW per month, ISO-NE states that the Installed Capacity Requirement

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[25] Market Rule 1 § III.13.

[26] ISO-NE Transmittal Letter at 23 (citing Wong Test. at 31-32). ISO-NE notes that these values are 241 MW and 152 MW less, respectively, than the values used in the second annual reconfiguration auction and 521 MW and 408 MW less, respectively, than the values used in the primary FCA.

[27] ISO-NE Transmittal Letter at 23 (citing ISO-NE Filing, Wong Test. at 32). ISO-NE notes that this value is 28 MW less than the value used in the second annual reconfiguration auction and 158 MW less than the value used in the primary FCA.

value should be 31,110 MW. These values would result in a reserve margin of 9.7 percent, which, ISO-NE notes, is significantly less than the reserve margin required in neighboring control areas.[28] ISO-NE states that the Installed Capacity Requirement proposed for the final annual reconfiguration auction is 1,027 MW less than the Installed Capacity Requirement approved by the Commission for the previous annual reconfiguration auction, which, in turn was 168 MW less than the Installed Capacity requirement approved for the 2010/2011 FCA. Both ISO-NE and NEPOOL acknowledge that a tie benefits value of 3,415 MW (resulting from the "as-is" analysis) is too high.

20. Alternatively, NEPOOL proposes an Installed Capacity Requirement of 30,684 MW, using a capped tie benefits value of 2,286 MW. NEPOOL argues that the use of the 2,286 MW value still results in an Installed Capacity Requirement that meets the New England resource adequacy criterion of 0.1 LOLE.

D. Stakeholder Process

21. ISO-NE states that there were two meetings in which the stakeholder committees voted on the Installed Capacity Requirement-related values for the 2010/2011 Capability Year and the proposed revisions to the Market Rules.

22. At its November 19, 2009 meeting, the Participants Committee failed to approve ISO-NE's proposed Installed Capacity Requirement-related values and HQICC values, with a vote of 18.5 percent in favor. In both the Reliability and Participants Committees, various proposals regarding Installed Capacity Requirement-related values were presented. Ultimately, the Participants Committee voted to approve the proposal put forth by the Massachusetts Attorney General (Mass AG) to cap tie benefits, with a vote of 66.612 percent in favor. Finally, the Participants Committee also failed to support ISO-NE's proposed revisions to Market Rule 1, section 12.9, with a vote of 11.658 percent in favor.

23. At the November 19, 2009 Participants Committee Meeting, a vote was taken on the Mass AG's proposal (which was adopted as the NEPOOL Amendment) to cap the tie benefits value at 2,286 MW for the 2010/2011 and 2011/2012 Commitment Periods. Implicit in the proposal is a required change to the existing section 12.9 of Market Rule 1, as recognized in the resolution voted on, in the minutes, and in the notice of actions for that meeting. The NEPOOL Amendment was supported by the NEPOOL Participants Committee with a vote of 66.61 percent in favor, with opposition from the generation and supplier sectors of ISO-NE, who continued to voice concern that the Installed Capacity

[28] ISO-NE Transmittal Letter at 15.

Requirement values were too low and failed to recognize the capacity needs of New England.[29]

E. The Alternative Proposed NEPOOL Amendment

24. NEPOOL objects to ISO-NE's calculation of tie benefits on the ground that ISO-NE's method adds unnecessary cost for consumers to bear (because a lower tie benefits value necessitates a higher Installed Capacity Requirement). NEPOOL states that ISO-NE "considered the 3,415 MW tie benefit value too high, and stated that it could result in over-reliance on tie benefits, even though use of the value in calculating [the Installed Capacity Requirement] would still result in an [Installed Capacity Requirement] that met the New England resource adequacy criterion."[30] NEPOOL recognizes the need to meet reliability standards but questions the cost to consumers to meet these standards. NEPOOL proffers an alternative proposed tie benefits value related amendment to section III.12.9 of Market Rule 1. Therefore, NEPOOL proposes to resolve the issue of tie benefits for the final annual reconfiguration auction by capping the tie benefits value at 2,286 MW for the 2010/2011 and 2011/2012 Capability Years. NEPOOL states that this proposal is more consistent with existing section 12.9 of Market Rule 1 as compared to ISO-NE's proposal.[31]

25. NEPOOL states that its proposal preserves the "as is" methodology in its calculation and simply implements a cap on the tie benefits value that can be used in the Installed Capacity Requirement calculation for the final reconfiguration auction. The NEPOOL Amendment also includes a sunset period to allow time for NEPOOL, ISO-NE, and ISO-NE's stakeholders to agree upon a permanent methodology regarding the

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[29] NEPOOL Transmittal Letter at 8.

[30] NEPOOL Transmittal Letter at 6.

[31] NEPOOL Transmittal Letter at 10. NEPOOL quotes *ISO New England Inc.*, 118 FERC ¶ 61,157, at P 49 (2007):

> We [the Commission] agree with ISO-NE that it is appropriate to use "as is" for the Annual Reconfiguration Auction two months before the Capacity Commitment period. This allows the reconfiguration auction to more accurately reflect the [Installed Capacity Requirement] needed to ensure that there is enough generation to reliably meet load in New England without over-relying on neighboring capacity and without overcharging New England customers for unnecessary capacity.

calculation of tie benefits for the last reconfiguration auction. NEPOOL contends that its proposed Amendment "recognizes the trade-off between reliability and cost, and accepts that it may be reasonable to establish an [Installed Capacity Requirement] that ensures even greater reliability than the LOLE criterion by capping the reliance that New England can place on its ties."[32] NEPOOL further argues that its proposed Amendment represents a reasonable compromise between reliability concerns and consumer cost. NEPOOL states that Mass AG's proposal (adopted here by NEPOOL) was far more acceptable to load and consumer stakeholders than what was suggested by ISO-NE. Additionally, NEPOOL argues that the inclusion of a two-year sunset provision allows ISO-NE and its stakeholders to establish a tie benefits methodology acceptable to all parties for the long term.

26. NEPOOL states that the LIPA methodology, which underlies the NEPOOL Amendment, used an "at criteria" approach and resulted in a tie benefits value of 2,540 MW. NEPOOL submits that this tie benefits value falls within the amount necessary to meet the LOLE reliability criteria, but Mass AG proposed an additional reduction of 10 percent "to be conservative."[33] NEPOOL states that the resulting value of 2,286 MW also meets the LOLE reliability criteria for the New England area while producing an Installed Capacity Requirement value 761 MW less than ISO-NE's 2010/2011 proposal.

27. NEPOOL clarifies that the Participants Committee vote in favor of the 2,286 MW tie benefits value should not be construed as endorsement of the LIPA methodology. Instead, the results of the methodology were found to be reasonable by the Participants Committee in light of the circumstances.[34] NEPOOL states that the determination of the precise value for the Installed Capacity Requirement is not an exact science, and, as such, many assumptions must be used in order to determine an appropriate value, including assumptions associated with load forecasts, capacity resource availability, and tie benefits. NEPOOL contends that the Market Rules act as a guide in developing and using such assumptions. NEPOOL states that the fact that the stakeholders used the Market Rules while actively engaging in negotiations and discussions regarding the tie benefits value, and ultimately agreed to the 2,286 MW value, confirms NEPOOL's assertion that its Amendment is both just and reasonable and an adequate compromise for the next two years until ISO-NE and NEPOOL resolve the dispute over a proper tie benefits methodology.

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[32] NEPOOL Transmittal Letter at 10.

[33] NEPOOL Transmittal Letter at 11 n.20.

[34] NEPOOL Transmittal Letter at 11 n.20.

28. Thus, NEPOOL proposes to amend section III.12.9 of Market Rule 1 to preserve the existing, Commission-approved provision regarding the use of an "as is" calculation of tie benefits for the final annual reconfiguration auction, but places a cap on the amount of tie benefits that can be assumed in the Installed Capacity Requirement calculation for the third annual reconfiguration for both the 2010/2011 and 2011/2012 Capacity Commitment Periods. Additionally, NEPOOL's proposal requires ISO-NE to file proposed market rule amendments by December 31, 2010, that would reflect a permanent methodology to calculate a tie benefits value for the third annual reconfiguration auctions beginning with the auction for the 2012/2013 Commitment Period.

F. Jump Ball Provision

29. NEPOOL contends that the "jump ball" provision of section 11.1.5 of the Participants Agreement, which allows NEPOOL to submit an alternative proposal, applies to this filing because ISO-NE is recommending changes to Market Rule 1 in the Tariff.[35] NEPOOL states that section 11.1.5 specifically governs circumstances in which ISO-NE and NEPOOL propose different amendments to the Market Rules of ISO-NE's Tariff. NEPOOL states that the amendment it is proposing is a Market Rule proposal that is different from the one proposed by ISO-NE and is subject to the broad definition of "Market Rules" as set forth in the Participants Agreement.[36] NEPOOL concludes that ISO-NE has interpreted section 11.4 too narrowly, which ultimately limits NEPOOL's rights and the Commission's authority to consider alternative amendments to ISO-NE's Market Rule proposal.

30. ISO-NE, in turn, maintains that the jump ball provision does not apply to this filing because ISO-NE's proposed amendment in its filing falls under the provisions of section 11.4 of the Participants Agreement, which is a special provision that governs and establishes "unique treatment" with respect to Installed Capacity Requirements.[37]

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[35] *See supra* notes 2 and 4.

[36] NEPOOL Transmittal Letter at 5. NEPOOL avers that the Participants Agreement defines Market Rules broadly to include all of the market rules and does not carve out any market rules that relate specifically to the Installed Capacity Requirement, which the language could have done if that were the intent of the parties: "'Market Rules' shall mean the rules for the administration of the New England Market filed with the Commission in accordance with this Agreement and accepted by the Commission." NEPOOL Transmittal Letter at 5 n.10 (citing Participants Agreement § I (Definitions)).

[37] ISO-NE Transmittal Letter at 6. ISO-NE quotes section 11.4 of the Participants Agreement, explaining that it requires ISO-NE to determine and file with the Commission, pursuant to section 205 of the FPA, Installed Capacity Requirements.

ISO-NE argues that the process outlined in section 11.4 does not require that alternative proposals be examined by the Commission. ISO-NE explains that it is proposing to revise section 12 of Market Rule 1 to revise the methodology used for calculating the tie benefits value—an integral part of the calculation for Installed Capacity Requirement-related values. Further, ISO-NE believes that, since the tie benefits *value* is not subject to the jump ball provision, it follows that the *methodology* for determining the tie benefits value is not subject to the jump ball provision. ISO-NE also maintains that, because the Installed Capacity Requirement is a reliability function, the Installed Capacity Requirement and the related rules in section 12 of Market Rule 1 "are not treated in exactly the same manner as the other sections of the market rules."[38] Therefore, ISO-NE states that this filing should be considered a section 205 filing and NEPOOL's amendment should not be considered by the Commission. Although ISO-NE does not believe that the jump ball provision applies to this filing, ISO-NE presented NEPOOL's alternative proposal, pursuant to section 11.1.5.

G. Requested Effective Date

31. ISO-NE requests that, in order to accommodate the implementation of the third annual reconfiguration auction being held in March 2010, the Commission grant an effective date of 60 days after the date of submission.

II. Notice of Filing and Responsive Pleadings

32. Notice of the filing was published in the *Federal Register*, 74 FR 68818 (2009), with interventions and protests due on or before January 8, 2010.[39] Timely motions to intervene were filed by NRG Companies;[40] Long Island Power Authority and the Long Island Lighting Company (collectively, LIPA); Bridgeport Energy, LLC; the Boston Generating Companies;[41] the New England States Committee on Electricity (NESCOE); Exelon Corporation; Northeast Utilities Service Company; Dynegy Power Marketing Inc. and Casco Bay Energy Company, LLC (collectively, Dynegy); Consolidated Edison

[38] ISO-NE Transmittal Letter at 6-7.

[39] On December 20, 2009, the Mass AG's motion for a three-day extension of the deadline for comments was granted.

[40] The NRG Companies consist of NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC.

[41] The Boston Generating Companies consist of Boston Generating, LLC; Mystic Development, LLC; Mystic I, LLC; and Fore River Development, LLC.

Energy, Inc.; GDF SUEZ Energy Marketing NA, Inc.; and North American Energy Alliance, LLC. The Vermont Department of Public Service timely filed a motion to intervene, and the Vermont Public Service Board joined with a notice of intervention; they submitted a joint motion for partial rejection. The Maine Public Utilities Commission filed a notice of intervention.

33. On December 22, 2009, the Mass AG submitted a motion to intervene and a motion for a three day extension of time for all parties to submit comments in this proceeding.

34. On January 11, 2010, NSTAR Electric Company filed a motion to intervene out-of-time.

35. Timely motions to intervene and comments were filed by the Mirant Parties;[42] PSEG Companies;[43] NSTAR Electric Company; LIPA; National Grid USA, The United Illuminating Company, Associated Industries of Massachusetts, and The Energy Consortium (collectively, the Joint Commenters); Massachusetts Department of Public Utilities (Mass DPU); New England Conference of Public Utilities Commissioners, Inc. (NECPUC); and the Connecticut Office of Consumer Counsel. The Connecticut Department of Public Utility Control (Connecticut DPUC) submitted a notice of intervention and comments.

36. NESCOE and the Vermont Department of Public Service (on behalf of itself and the Vermont Public Service Board, collectively, Vermont) timely filed comments. NEPOOL filed supplemental comments on January 8, 2010. On January 13, 2010, Connecticut DPUC filed a motion to submit clarifying comments.

37. Public Systems[44] and Mass AG filed motions to intervene and limited protests. Mass AG was a proponent of the Market Rule revision that the Participants Committee ultimately approved as the NEPOOL Amendment.[45]

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[42] The Mirant Parties consist of Mirant Energy Trading, LLC; Mirant Canal, LLC; and Mirant Kendall, LLC.

[43] The PSEG Companies consist of PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC.

[44] Public Systems consist of Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative, Inc.

[45] Mass AG Protest at 2.

38. On January 25, 2010, ISO-NE submitted an answer.

III. Discussion

A. Procedural Matters

39. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2009), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

40. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2009), the Commission will grant NSTAR Electric Company's late-filed motion to intervene given their interest in the proceeding and the absence of any undue prejudice or delay.

41. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept ISO-NE's answer because it has provided information that assisted us in our decision-making process.

B. Jump Ball Provision

1. Comments

42. Mass AG adopts NEPOOL's arguments by reference and submits further comments in support of the NEPOOL Amendment. Mass AG states that ISO-NE's and NEPOOL's proposals are before the Commission pursuant to section 11.1.5 of the Participants Agreement and are subject to the jump ball provision because the proposed Market Rule revision that was the outcome of the stakeholder process differs from ISO-NE's Market Rule proposal.[46] Mass AG argues that ISO-NE is attempting to expand the scope of section 11.4 beyond Installed Capacity Requirement *values* to include Installed Capacity Requirement-related *market rules*.[47] Mass AG concurs with NEPOOL that section 11.4 does not address amendments to Market Rules and that the section only requires ISO-NE to present Installed Capacity Requirement values to the stakeholder process for advisory votes. Thus, Mass AG argues that any Market Rule revision is subject to the stakeholder processes as delineated in preceding sections 11.1.2 and 11.1.3.[48] Mass AG claims that, as a policy and legal matter, the Commission should

[46] Mass AG Protest at 2.

[47] Mass AG Protest at 3.

[48] Mass AG Protest at 3.

uphold the jump ball provision to prevent ISO-NE from ignoring the input of stakeholders now and in the future.[49]

43. According to Joint Commenters, ISO-NE has overstepped its authority in determining a tie benefits value and ISO-NE's actions have left many stakeholders feeling that their rights and interests have been ignored. Joint Commenters support the NEPOOL Amendment because it maintains the "as is" methodology, preserves reliability, implements an interim change to allow for further study and analysis, and provides a target date for submission of a permanent tie benefits rule.[50] Joint Commenters agree with NEPOOL that proposals to amend the methodology for determining tie benefits, and thereby affecting the Installed Capacity Requirement, are subject to the jump ball provision. They state that the only way ISO-NE could avoid the requirements of section 11.1.5 would be to establish that ISO-NE's proposal to change the wording of section 12.9 of Market Rule 1 is not a "Market Rule proposal." However, because ISO-NE's proposal would amend the words, meaning, and effect of section 12.9, Joint Commenters maintain that it is clear ISO-NE's proposal is a "Market Rule proposal," falling under the jump ball provision.[51] Joint Commenters dispute ISO-NE's claim that the provisions of section 11.4 outweigh the provisions of section 11.1.5 and maintain that ISO-NE's interpretation of its authority under section 11.4 is too expansive.[52] Joint Commenters state that section 11.4 entitles ISO-NE to calculate and file the Installed Capacity Requirement based on "unmolested" Market Rules.[53] They also state that section 11.4 is silent on the subject of the jump ball provision because section 11.4 focuses on Installed Capacity Requirement values, not Market Rules.[54] Joint Commenters state that the Commission should reject ISO-NE's filing; if the Commission finds that the jump ball provision applies, it should reject ISO-NE's proposal in favor of the (temporary) NEPOOL Amendment, since such a determination would be consistent with the inability of the parties to make a permanent rule change at this time.[55]

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[49] Mass AG Protest at 4.

[50] Joint Commenters Comments at 11-12.

[51] Joint Commenters Comments at 15.

[52] Joint Commenters Comments at 15-16.

[53] Joint Commenters Comments at 16.

[54] Joint Commenters Comments at 17.

[55] Joint Commenters Comments at 19-20.

44. Public Systems state that ISO-NE's proposal should be rejected and argues that section 11.1.5 of the Participants Agreement preserves certain section 205 rights to the NEPOOL Participants acting collectively.[56] Public Systems maintain that, because the NEPOOL Amendment garnered more support than the rival ISO-NE proposal, the NEPOOL Amendment falls under the requirements of section 11.1.5 and the jump ball provision.[57] Public Systems state that the jump ball provision does not provide exceptions for particular kinds of market rule proposals.[58] They also state that section 11.4 does not create a *sub silentio* exception for all Installed Capacity Requirement-related market rule changes. According to Public Systems, even if there were ambiguity about whether the instant situation fits within section 11.1.5, the Commission should resolve the issue by applying the jump ball provision.[59] Public Systems state that applying the jump ball provision in this instance minimizes the risk that NEPOOL Participants will be deprived of their section 205 rights and promotes good governance and sound decision-making. [60] Public Systems point out that NEPOOL's proposal establishes a numerical cap and provides that the existing "as is" methodology will remain effective until a new methodology has been adopted.[61] Finally, Public Systems note that, in cases where ISO-NE has filed Installed Capacity Requirement values supported by the stakeholders, ISO-NE has been quick to point out the stakeholder consensus and to urge the Commission to defer to it.[62]

45. Vermont agrees with the argument advanced by Joint Commenters that both of the proposals submitted by NEPOOL and ISO-NE are Market Rule changes and, therefore, NEPOOL's proposed amendment is governed by the jump ball provision of section 11.1.5 of the Participants Agreement. As a result, Vermont argues, "the Commission is authorized to approve the proposal that it finds just and reasonable and preferable, notwithstanding the otherwise applicable provisions of Section 205 of the [FPA]."[63]

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[56] Public Systems Comments at 6.

[57] Public Systems Comments at 6.

[58] Public Systems Comments at 7.

[59] Public Systems Comments at 8.

[60] Public Systems Comments at 8.

[61] Public Systems Comments at 6 (citing ISO-NE Transmittal Letter at 6-7 & n.21).

[62] Public Systems Comments at 10.

[63] Vermont Comments at 4.

46. NESCOE urges the Commission to recognize the jump ball provision as applicable to NEPOOL's Amendment for the reasons set forth by NEPOOL.[64] NESCOE states that the jump ball provision offers an important check and balance in New England's process.[65]

47. The Connecticut DPUC urges the Commission "to give substance to NEPOOL's carefully negotiated governance mechanisms" and to heed the objections to ISO-NE's proposal for determining tie benefits in the FCM's third reconfiguration auction.[66]

48. In its answer, ISO-NE reiterates that the jump ball provision is inapplicable to market rule revisions that address the calculation of the Installed Capacity Requirement and, in particular, to a rule change that simply establishes a value.[67] ISO-NE again states that, because the Installed Capacity Requirement value is not subject to the jump ball provision, it follows that the calculation methodology is not subject to the provision.

49. In its supplemental comments, NEPOOL states that its amendment meets the two threshold requirements for application of the jump ball provision. First, it is "a Market Rule proposal that is different from the one proposed by ISO," and second, the NEPOOL Amendment received a Participants Committee vote equal to or greater than 60 percent. Thus, NEPOOL argues that it has the right to have its amendment submitted on equal footing with ISO-NE's Market Rule change as a filing under section 205 of the Federal Power Act.

50. Further, NEPOOL avers that ISO-NE's argument against the applicability of section 11.1.5 is wrong for at least four reasons. First, NEPOOL states that the "plain meaning" of section 11.1.5 requires its application in this situation; the Participants Agreement defines the term "Market Rules" as used in section 11.1.5 broadly to include all of the Market Rules and does not carve out any that relate to the Installed Capacity Requirement. Second, NEPOOL states that ISO-NE is incorrect in its argument that NEPOOL's interpretation of section 11.1.5, as being applicable to the Installed Capacity Requirement related Market Rule amendments, would render section 11.4 meaningless. According to NEPOOL, section 11.4 addresses the periodic determinations and filings of the Installed Capacity Requirement that ISO-NE must do under the Market Rules in effect, and ISO-NE would still have discretion regarding such determinations and filings,

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[64] NESCOE Comments at 3.

[65] NESCOE Comments at 3.

[66] Connecticut DPUC Supplemental Comments at 2.

[67] ISO-NE Answer at 18.

subject to existing Market Rules. Third, NEPOOL argues that ISO-NE is incorrect in its argument that references to the Participant Processes and to the Market Rules in section 11.4 mean that ISO-NE has sole discretion to file Installed Capacity Requirement-related Market Rule changes. Instead, NEPOOL contends that these references refer to the fact that ISO-NE must take its Installed Capacity Requirement determinations through the NEPOOL stakeholder process for advisory votes just as it would for proposed changes to the Market Rules, but it has discretion regarding what to file for those ICR determinations under the existing rules. Lastly, NEPOOL finds incorrect ISO-NE's argument that, because the subject Market Rule change was reviewed by the NEPOOL Reliability Committee rather than the NEPOOL Markets Committee, the jump ball provision does not apply. NEPOOL argues that the fact that one technical committee versus another committee reviews a Market Rule has no relevance to whether the Market Rule amendment is subject to the jump ball provision.

2. Commission Determination

51. This is the first time the Commission has been asked to determine the applicability and operation of section 11.1.5 of the Participants Agreement. In pertinent part, the jump ball provision states that, if an ISO Market Rule proposal that differs from that proposed by ISO-NE is approved by a Participants Committee vote of 60 percent or more, ISO-NE "shall, as part of any required Section 205 filing," describe the alternate Market Rule proposal in sufficient detail to permit reasonable review by the Commission and also explain its reasons for not adopting the alternate proposal and why it believes its own proposal is superior. Section 11.1.5 provides that the Commission need not consider whether the then-existing filed rate is not just and reasonable and may "adopt all or any of ISO[-NE]'s Market Rule proposal or the alternate Market Rule proposal as it finds … to be just and reasonable and preferable." As we discuss below, we find that section 11.1.5 applies by its terms to a proposed change in the calculation method for the Installed Capacity Requirement.

52. ISO-NE contends that it is carrying forward the tie benefits methodology used in support of previous auctions, which does not constitute a "new" proposal or "change."[68] ISO-NE explains that its proposed change is a clarification of the methodology used for calculating the tie benefits value, which methodology is an integral part of the calculation for Installed Capacity Requirement-related values. ISO-NE relates the tie benefits *value* and the tie benefits *methodology*, averring that, if the *value* is not subject to the jump ball provision, it follows that the *methodology* for determining the tie benefits value is not subject to it. Finally, ISO-NE states that the Installed Capacity Requirement is a reliability function, and the Installed Capacity Requirement and the related rules in

[68] ISO-NE Answer at 11, 12.

section 12 of Market Rule 1 "are not treated in exactly the same manner as the other sections of the market rules."[69]

53. By its terms, section 11.1.5 applies only to Market Rule proposals. Thus, we must first determine whether a proposed change in the calculation method for the Installed Capacity Requirement is, in fact, a change to a Market Rule. If not, then section 11.4 would apply. ISO-NE and NEPOOL dispute over whether section 11.4 or 11.1.5 of the Participants Agreement is applicable to a proposed change to the calculation methodology for the Installed Capacity Requirement in Market Rule 1, which is found in section III.12.9 of ISO-NE's Tariff. ISO-NE maintains that such a proposal falls under section 11.4 (entitled Installed Capacity Requirements), because section 11.4 is a special provision that governs and establishes "unique treatment" for Installed Capacity Requirements.[70] ISO-NE maintains that the process outlined in section 11.4 does not require that alternative proposals be examined by the Commission. It explains that section 11.4 provides that the Installed Capacity Requirements are subject to the market rule voting provisions in sections 11.1.2 and 11.1.3 of the Participants Agreement but makes no mention of section 11.1.5. According to ISO-NE, section 11.4's explicit reference to certain subsections of section 11.1 (specifically, 11.2 and 11.3) means that other subsections are thereby excluded;[71] therefore, the jump ball provision of section 11.1.5 does not apply.

54. Alternatively, NEPOOL contends that the jump ball provision of section 11.1.5 applies to this filing because ISO-NE is recommending changes to Market Rule 1 in the Tariff, and section 11.1.5 specifically governs circumstances in which ISO-NE and NEPOOL propose different amendments to the Market Rules of ISO-NE's Tariff, which is the situation at hand. NEPOOL's argument rests on its contention that its proposal is "a Market Rule proposal that is different from the one proposed by ISO," and the NEPOOL Amendment received a Participants Committee vote that was more than 60 percent in favor.

55. We find that the proposed change in the calculation methodology in the Installed Capacity Requirements involves a change to a Market Rule, and, thus, section 11.1.5 (along with the rest of section 11.1) applies, not section 11.4.[72] Section 11.1 of the

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[69] ISO-NE Transmittal Letter at 6-7; ISO-NE Answer at 18-19.

[70] ISO-NE Transmittal Letter at 6.

[71] ISO-NE Transmittal Letter at 6 (citing the legal doctrine, *expressio unius est exclusio alterius*).

[72] In light of this finding, we need not reach the question of whether section 11.1.5 applies to a filing made under section 11.4.

Participants Agreement (titled, General Provisions) requires ISO-NE "to present proposals for changes to Market Rules," etc., for Governance Participant consideration and NEPOOL Participant vote, in accordance with the subsequent provisions in section 11.[73] The term, "Market Rules," is defined as "the rules for the administration of the New England Markets [filed with and accepted by the Commission]."[74] ISO-NE states that it is proposing "a change to Section 12.9 of Market Rule 1, which governs the methodology for calculating the Installed Capacity Requirement."[75]

56. Specifically, section III.12.9 of Market Rule 1 in ISO-NE's Tariff provides, in relevant part:

> The ISO shall calculate tie benefits using "at-criteria" assumptions for purposes of modeling the adjacent Control Areas, except that when calculating the Installed Capacity Requirement, the Local Sourcing Requirements and Maximum Capacity Limits for use in the annual reconfiguration auction closest to the relevant Capacity Commitment Period, the ISO shall calculate tie benefits using "as-is" data for the purposes of modeling the adjacent Control Areas.[[76]]

ISO-NE proposes to use the "at criteria" in place of the "as is" methodology to generate values for the final reconfiguration auction. Rather than merely "determin[ing] and fil[ing] … the Installed Capacity Requirements for [the 2010/2011] Power Year,"[77] ISO-NE "recommends changing the market rules to use the value calculated for the primary Forward Capacity Auction for all three annual reconfiguration auctions."[78] ISO-NE explains that the use of the "as is" methodology, currently provided in Market Rule 1, results in a tie benefits value of 3,415 MW, which ISO-NE characterizes as "extremely high."[79] Thus, ISO-NE proposes to correct the status quo with "market rule

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[73] Participants Agreement § 11.1.

[74] Participants Agreement § 1 (Definitions).

[75] Joint Transmittal Letter at 2; ISO-NE Transmittal Letter at 2.

[76] Market Rule 1, § III.12.9.

[77] Participants Agreement § 11.4 (Installed Capacity Requirements).

[78] ISO-NE Transmittal Letter at 3.

[79] ISO-NE Transmittal Letter at 3.

revisions that address the calculation of the Installed Capacity Requirement."[80] Therefore, section 11.1 of the Participants Agreement is applicable to ISO-NE's filing because ISO-NE is proposing a change to the Market Rules. Accordingly, ISO-NE's proposal implicates the procedures in sections 11.1.2 and 11.1.3 (Technical Committee and Participants Committee Review, respectively), as well as the jump ball provision in section 11.1.5 (Alternative Committee Market Rule Proposal). Section 11.1.5 requires that ISO-NE present to the Commission any alternative Market Rule proposal that is approved by a Participant vote of at least 60 percent, which would include NEPOOL's proposal.

57. ISO-NE proposes that the tie benefits calculation methodology that was used previously should apply to this final reconfiguration auction. We find that ISO-NE's proposed calculation methodology is a tariff change. ISO-NE's proposed methodology (i.e., using "at criteria") is different from the methodology currently provided in the Tariff (i.e., the "as is" methodology). Further, while the tie benefits *value* and the tie benefits *methodology* are clearly related as ISO-NE argues, we are not persuaded that it follows that, if the *value* is not subject to the jump ball provision, the *methodology* for determining the tie benefits value likewise is not subject to it. ISO-NE determines and files Installed Capacity Requirements—the *values*—under section 11.4 . The *methodology* for calculating those values, however, is part of the Market Rules and, as such, any proposed amendment to the methodology comes under the provisions of section 11.1. Read within the full context of section 11 and its individual subparts, we find that the proposals at issue here involve changes to the *methodology* for calculating the Installed Capacity Requirements, not the *values*, and thus fall within the scope of section 11.1, which includes the jump ball provision, rather than section 11.4.[81]

C. Tie Benefits Proposals, Installed Capacity Requirements, and Related Values

1. Comments

58. Joint Commenters note that both ISO-NE and NEPOOL agree that substantial additional technical and analytical work is needed before a final, permanent change to section III.12.9 can properly be proposed.[82] Joint Commenters state that ISO-NE previously has stated that "as is" assumptions are more likely to be accurate than "at-

[80] ISO-NE Transmittal Letter at 3.

[81] *See supra* note 75.

[82] Joint Commenters Comments at 9 (citing ISO-NE Transmittal Letter at p. 4; Karl Testimony at 16-17).

criterion" assumptions.[83] Joint Commenters state that sufficient study, analysis, and consultation is needed to identify the specific weaknesses in the earlier position and put in place a robust and effective modification that the parties can support as just and reasonable.[84] NESCOE agrees that, contrary to the stakeholder process and despite requests, ISO-NE did not provide any real analysis of alternative proposals; a detailed explanation of reliability needs, estimated emergency events, and cost implications of the various options; or a rationale for reaching its preferred decision or proposal.[85]

59. Vermont states that, if the Commission determines that section 11.1.5 of the Participants Agreement is not applicable to this filing, the Commission should reject ISO-NE's filing because it "does not pass muster" under the section 205 requirements of being just and unreasonable and not unduly discriminatory.[86] Vermont agrees with the argument put forth by Joint Commenters and adds that, while NEPOOL has proposed an interim tariff change that would establish a temporary tie benefit cap of 2,286 MW, ISO-NE has proposed tariff language that would replace, without time limit, the current "as is" methodology enumerated in section III.12.9 of Market Rule 1 with the previously-used "at criteria" approach to determine tie benefits.

60. Several commenting parties state that they disagree with ISO-NE's proposal to permanently change the Market Rules and disregard the on-going stakeholder process related to tie benefits issues.[87] NSTAR states that ISO-NE's proposal is inconsistent with the FCM settlement and the Commission's directive that the "as-is" criterion be used for the third annual reconfiguration auction.[88] NESCOE states that ISO-NE does not argue

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[83] Joint Commenters Comments at 12-13 (citing Motion for Leave to Answer and Answer of ISO New England, Inc., Docket No. ER07-365-000, at 28 (filed Feb. 1, 2007).

[84] Joint Commenters Comments at 13-14.

[85] NESCOE Comments at 5-6.

[86] Vermont Comments at 4.

[87] NESCOE Comments at 2; Mass DPU Comments at 3; NECPUC Comments at 1; Mass AG Protest at 8; Joint Commenters Comments at 6.

[88] NSTAR Comments at 5 (citing *ISO New England, Inc.*, 118 FERC ¶ 61,157 (2007)).

that its proposed Market Rule modification is the proper long-term regional solution.[89] Further, NESCOE points out that ISO-NE does not have NEPOOL support.[90]

61. Joint Commenters assert that they would not object to a Commission order adopting ISO-NE's 1,860 MW tie benefit value, if this were explicitly adopted as an interim Market Rule just as NEPOOL proposes for its 2,286 MW tie benefit cap.[91] Joint Commenters maintain that such a "hybrid" order would be possible under the jump ball provision, though not under ISO-NE's more limiting section 205 filing approach.[92] Those who oppose ISO-NE's proposal support the NEPOOL Amendment, stating that NEPOOL's proposal is an interim compromise that envelops the stakeholder process and does not permanently dispose of the Commission-approved "as-is" methodology.[93] In addition, Joint Commenters supports NEPOOL's amendment because it provides a target date for the submission of a permanent tie benefits rule.[94]

62. A number of commenting parties rooted their support for the NEPOOL Amendment on the premises that it does not violate New England's accepted reliability criteria and effectively balances ISO-NE's reliability needs and cost considerations.[95] Mass DPU noted that even ISO-NE seems to agree that NEPOOL's tie benefit value is within a "zone of reasonableness" and would not threaten reliability.[96]

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[89] NESCOE Comments at 4 (citing ISO-NE Filing, Karl Test. at 18, lines 1-9).

[90] NESCOE Comments at 2 (citing ISO-NE Filing, Karl Test. at 25-26).

[91] Joint Commenters Comments at 20.

[92] Joint Commenters Comments at 20.

[93] NSTAR Comments at 4; Mass AG Limited Protest at 7; Connecticut DPUC Comments at 5-6; NESCOE Comment at 2; and Joint Commenters Comments at 11-12.

[94] Joint Commenters Comments at 11-12.

[95] NSTAR Comments at 4; NEPOOL Supplemental Comments at 7; Mass DPU Comments at 3; Mass AG Protest at 4; 8 (citing NEPOOL Filing, Plett Test. at 11); NESCOE Comments at 1; Joint Commenters Comments at 21 (citing NEPOOL Transmittal Letter at 10; Plett Test. at 11-12).

[96] Mass DPU Comments at 3 (citing ISO-NE Filing, Karl Test. at 21).

63. NECPUC[97] and Mass DPU[98] assert that the Commission, as an economic regulator, must balance reliability and costs to consumers. Mass DPU[99] and NESCOE[100] state that ISO-NE's proposal is heavily weighted toward reliability without sufficient consideration for costs; since the Commission's role as an economic regulator is to balance reliability and cost, NESCOE states that substantive consideration of both NEPOOL's and ISO-NE's proposals is essential.[101] Mass AG states that the additional capacity required under ISO-NE's proposal represents an unnecessary cost and that it is unjust and unreasonable to charge consumers for capacity that does not contribute to reliability.[102]

64. NESCOE asserts that ISO-NE's conclusion that its proposed value is superior to alternatives because it is grounded in the Commission's prior approval of these values is flawed.[103] NESCOE asserts that ISO-NE provides no assessment that assumptions developed during 2007 form a reliable basis for calculating tie benefits for the upcoming 2010/11 commitment period, particularly in comparison to other assumptions that might be relied upon as a basis for alternative tie benefits values.[104] NESCOE argues that, basing conclusions about the reasonableness of a value on the fact that this value was approved in a prior time is not a "sound analytical basis."[105] Addressing the fact that the capped NEPOOL tie benefits value of 2,286 MW was based on the wrong commitment period, Mass AG asserts that the difference in data between 2011/2012 and 2010/2011, if

[97] NECPUC Comments at 1.

[98] Mass DPU Comments at 3.

[99] Mass DPU Comment at 3.

[100] NESCOE Comments at 2.

[101] NESCOE Comments at 1-2; Mass DPU Comments at 3.

[102] Mass AG Protest at 9.

[103] NESCOE Comments at 7 (citing ISO-NE Filing, Karl Test. at 16).

[104] NESCOE Comments at 8.

[105] NESCOE Comments at 8 (citing ISO-NE Transmittal at 3).

any, is likely to be small and would be subsumed by the 10 percent discount of the 2,540 MW tie benefit value calculated under the LIPA method.[106]

65. NESCOE claims that ISO-NE provides no specific allegations that the methodology used in the LIPA approach provides an unreasonable approach for determining tie benefits.[107] Mass AG references Mr. Plett's rebuttal testimony, which states that the comparison of reserve margin percentages has no relevance to the New England calculation of Installed Capacity Requirements.[108] According to Mass AG, Mr. Plett further testifies that, prior to Mr. Karl's testimony, ISO-NE also had repeatedly rejected references to reserve margin as a means for setting Installed Capacity Requirements.[109]

66. Addressing ISO-NE's discussion of alternative stakeholder processes involving tie benefits, LIPA states that the treatment of an individual tie benefits calculation methodology is unrelated to the 2010/2011 reconfiguration auction, which is the subject of a separate Commission proceeding and should remain so.[110] LIPA further states that, given ISO-NE's own work on calculating tie benefits for individual transmission lines, it would be premature to assume that this issue cannot be concluded by the February 2010 compliance deadline—and certainly in sufficient time for integration into the August 2010 FCA for the 2013/2014 Capability Year.[111] LIPA also states that, even if such a conclusion is reached, it is incumbent upon ISO-NE to separately file a request for extension with the Commission and justify the need to further delay its compliance obligation.[112] Mirant notes that none of the related tie benefits issues have been voted on by stakeholders, and thus it is too early for ISO-NE to advise the Commission on their status in the stakeholder process.

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[106] Mass AG Protest at 6 (citing NEPOOL Filing, Plett Test. at 5 and ISO-NE Filing, Attachment I-1g (Mass AG Presentation Before the NEPOOL Participants Committee)).

[107] NESCOE Comments at 8.

[108] Mass AG Protest at 13 (citing NEPOOL Filing, Plett Test. at 2).

[109] Mass AG Protest at 13.

[110] LIPA Comments at 6.

[111] LIPA Comments at 7.

[112] LIPA Comments at 7.

67. NESCOE states that the concerns raised by Mr. Brandien with respect to the operational factors of the New England system should not affect tie benefit determinations.[113] Moreover, NESCOE states that Mr. Brandien's suggestion that his concerns could diminish tie benefits by 1,260 MW, resulting in a net 2,155 MW tie benefit level (3,415 MW less 1,260 MW), actually confirms the reasonableness of the NEPOOL Amendment, which proposes roughly 2,155 MW.[114] NESCOE maintains that, contrary to ISO-NE's assertion that the majority of stakeholders wanted to retain the "as is" tie benefits assumption,[115] a vote on the "as is" 3,415 MW value did not occur in the Reliability and/or the Participants Committee.[116] NESCOE also states that the Commission's detailed review of these issues could provide helpful guidance to the ongoing stakeholder process concerning Installed Capacity Requirement and tie benefit value questions currently under consideration.[117]

68. In its answer, ISO-NE states that, when the "as is" methodology was first applied to this reconfiguration auction, ISO-NE discovered that the resulting ties benefits value and Installed Capacity Requirement could have serious, negative implications for reliability. ISO-NE further states that its proposed change is temporary for use in the upcoming annual reconfiguration auction.[118] ISO-NE maintains that ISO-NE and NEPOOL conducted an open and fair stakeholder process; there was broad agreement among stakeholders regarding many of the assumptions, inputs, and projections. ISO-NE states that it is not proposing a "new" methodology for calculating tie benefits; rather, its proposal preserves the status quo. Moreover, ISO-NE contends that, as a general matter, when tie benefits are calculated on an "at criteria" basis, the potential for year-to-year changes and the magnitude of change in the level of tie benefits is significantly reduced.[119] ISO-NE states that it believes that the 1,860 MW level of tie benefits remains available from neighboring control areas. According to ISO-NE, because it has shown that the 3,415 MW value yields an unreliable result, the best choice is to use the

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[113] NESCOE Comments at 10.

[114] NESCOE Comments at 11 (citing ISO-NE Filing, Brandien Test. at 8).

[115] NESCOE Comments at 4 (citing ISO-NE Filing, Karl Test. at 18).

[116] NESCOE Comments at 4.

[117] NESCOE Comments at 3.

[118] ISO-NE Answer at 8.

[119] ISO-NE Answer at 12.

previously filed and Commission-approved 1,860 MW value.[120] ISO-NE notes that, to date, the "at criteria" has produced relatively stable tie benefits values. It states that Commission precedent requires Installed Capacity Requirement values to be based on reasoned and supported analyses of relevant data and assumptions and not on consensus. ISO-NE points out that the NEPOOL Amendment was not supported by any study applicable for the 2010/2011 Capability Year, nor was it grounded in a fully developed or vetted calculation methodology.[121]

69. In its supplemental comments, NEPOOL notes that ISO-NE's main argument against the NEPOOL Amendment is that the proposal has no sound basis and, instead, it reflects a majority of stakeholder votes. NEPOOL responds that ISO-NE ignores the fact that its own proposed value diverges from an analytically pure number, since the updated "at criteria" analysis actually results in tie benefits equal to 1,525 MW, rather than 1,860 MW, which was picked for "stability." As such, NEPOOL argues that the Commission is left with two proposals for tie benefits that could be acceptable from a reliability perspective, but only one of which is preferable from a stakeholder support and cost consideration perspective.

2. Commission Determination

70. As this filing establishes the Installed Capacity Requirement for the last reconfiguration auction of the first FCM commitment period, it represents the first application of the "as is" methodology. This joint filing also represents the first time a market rule revision has been proposed under the jump ball provision of section 11.1.5 of the Participants Agreement. After evaluating both proposed amendments under section 205 of the FPA, we find that ISO-NE's proposal is just and reasonable and preferable. For the reasons below, we find that there are significant deficiencies in NEPOOL's proposal. Therefore, we will accept ISO-NE's proposed Installed Capacity Requirement and related values for use in the final FCM reconfiguration auction for the 2010/2011 Capability Year, as well as the related proposed market rule change, subject to a condition.

a. "As Is" and "At Criteria" Methodologies

71. Tie benefits reflect the amount of emergency assistance that is assumed to be available to New England from neighboring control areas without jeopardizing reliability

[120] ISO-NE Answer at 13 (referring to ISO-NE Filing, Karl Test. at 16, which provides that developing a new tie benefits methodology is "unfeasible and inappropriate at this time since doing so would undercut the process already underway").

[121] ISO-NE Answer at 15-16.

in New England or its neighboring control areas. They are an important part of the Installed Capacity Requirement calculation, and their value is often controversial since tie benefits reduce the Installed Capacity Requirement and, thus, the amount of capacity purchased in the FCM for the commitment period. Under the terms of the current tariff, tie benefits from neighboring control areas are calculated under an "as is" methodology for the final reconfiguration auction prior to the relevant commitment year.[122] This methodology assumes that the neighboring control areas have resources and demands equivalent to those that were forecast for the commitment period and that these resources will be available to meet load within their respective areas. ISO-NE notes in its transmittal letter, however, that such forecasted resources and demands may be more or less than what is needed to meet the reliability requirements of the New England control area,[123] i.e., to prevent non-interruptible customers from being disconnected no more than once every ten years (0.1 LOLE).

72. The "as is" methodology is different from the "at criteria" methodology, which, under the current tariff, is used to calculate the tie benefits for all of the auctions prior to the last one for a given commitment period. The "at criteria" methodology assumes only that neighboring control areas have enough resources such that each area meets the reliability standard of 0.1 LOLE. The availability of external capacity may be unknown under this methodology. As ISO-NE explains, the basis for the switch to the "as is" methodology for the last reconfiguration auction was the belief that this methodology made theoretical sense due to the proximity of the last auction to the commitment period.[124] Since the last reconfiguration auction takes place approximately two months before the commitment period, it was assumed that the "as is" methodology would more accurately reflect the resources that will be available during the commitment period.[125] Further, as noted in the Karl testimony, during the FCM Settlement discussions, load representatives supported this methodology.[126] The basis for that support was that if the first two annual reconfiguration auctions failed to procure the Installed Capacity Requirement, rather than having ISO-NE purchase additional capacity in the last

[122] *See* Market Rule 1, § III.12.9.

[123] ISO-NE Transmittal Letter at 9.

[124] *Id.*

[125] *ISO New England Inc.*, 118 FERC ¶ 61,157, at P 49 (2007).

[126] ISO-NE Filing, Karl Test. at 24.

reconfiguration auction, ISO-NE could assess external capacity on an "as is" basis. The Commission approved this overall methodology in February 2007.[127]

73. While the "as is" methodology was approved by the Commission, it is clear that its application for the 2010/2011 commitment period would trigger operational concerns as highlighted by the testimonies of Mr. Brandien and Mr. Karl.[128] ISO-NE states that it has never been in a position of requiring 3,415 MW of emergency assistance and does not find the value to be realistic or achievable.[129] Commenters even note that while the current methodology theoretically satisfies the LOLE standard, it would be more likely that ISO-NE would need to take OP 4 (ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency) actions, including voltage reductions, and requests for emergency assistance from neighboring control areas. Though our specific consideration of the current methodology is not necessary under the terms of the jump ball provision, we nonetheless agree with both ISO-NE and NEPOOL that the use of the current "as is" methodology for the 2010/2011 commitment period would not be practical.

74. Our analysis of the tie benefits issue will need to determine both what is just and reasonable in the short term (for the 2010/2011 commitment period), as well as the long term (for future commitment periods). First, addressing the 2010/2011 commitment period, we note that it is possible that both proposed values are valid representations of tie benefits for the 2010/2011 commitment year; we recognize that there are a number of assumptions built into the Installed Capacity Requirement analysis and that the correct tie benefits value likely encompasses a range of values. We also agree with commenters that it is important to establish the proper Installed Capacity Requirement (and inherently, tie benefits value) "without overcharging New England customers for unnecessary capacity."[130] In fact, if we were presented with two equally defendable tie benefits values, all other things being equal, we may find the higher tie benefits number to be

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[127] *ISO New England Inc.*, 118 FERC ¶ 61,157 (2007).

[128] ISO-NE indicates that this "as is" tie benefits value reduces the Installed Capacity Requirement (from 33,705 MW for the primary auction and 33,537 MW for the first reconfiguration auction to 30,988 MW), resulting in a reserve margin over the peak load forecast of 4.3% (relative to a reserve margin of 9.7% with tie benefits equal to 1,860 MW). Although the filing does not explain why the "as is" tie benefits value is so relatively high (and whether ISO-NE previously had ever examined an "as is" tie benefits value for 2010/2011), due to reliability concerns, no parties support its use here.

[129] Transmittal letter at 13.

[130] *ISO New England Inc.*, 118 FERC ¶ 61,157 at P 49.

"more" just and reasonable, as it would reduce the Installed Capacity Requirement, minimizing the purchase of "unnecessary capacity." It is the absence of such a scenario before us, however, that defines our decision to adopt ISO-NE's tie benefits value of 1,860 MW, as opposed to NEPOOL's proposed value of 2,286 MW, for the 2010/2011 commitment period.

b. Tie Benefits Value: ISO-NE Proposal

75. Noting that several related areas of the Installed Capacity Requirement calculation are under stakeholder review, ISO-NE recommends revising section III.12.9 of Market Rule I to require the use of the tie benefits value calculated for the primary FCA (under the "at criteria" methodology) for all three annual reconfiguration auctions. In support, ISO-NE contends that such an approach would reduce significant year-to-year changes in tie benefits, provide stability to the marketplace and surrounding control areas, and result in a reserve margin for the 2010-2011 commitment period that is "acceptable" though still "significantly below" the reserve margin of neighboring control areas like New York. This approach would retain the 1,860 MW value of tie benefits for the 2010/2011 commitment period. However, ISO-NE notes that it does not advocate that the "as is" methodology should be eliminated in favor of the "at criteria" methodology, since some of the same problems may apply to both methodologies. Rather, ISO-NE acknowledges that due to the ongoing stakeholder discussions on tie benefits, any significant methodology changes at this time are premature. Instead, ISO-NE indicates that it is committed to a full review of all of the tie benefits issues and plans to file a comprehensive approach to all of the tie benefits issues by the end of 2010.[131] In separate votes, the Participants Committee failed to support ISO-NE's proposed Installed Capacity Requirement-related values for the 2010/2011 commitment period and ISO-NE's proposed revisions to section III.12.9 of Market Rule 1.

76. Based on ISO-NE's conclusion that "the resulting tie benefits value [of 3,415 MW] and Installed Capacity Requirement could have serious, negative implications for reliability,"[132] ISO-NE proposes to change the market rules to maintain the use of the tie benefits value of 1,860 MW calculated for the primary FCA and the two subsequent reconfiguration auctions.[133] We agree with ISO-NE that, while this issue remains to be

[131] On January 14, 2010, ISO-NE filed an update on the status of the "Reserved Issues" from Docket ER08-41-004, which required a February 2010 filing with the Commission. ISO-NE's update reiterates its position here that all tie benefits issues should be addressed in a comprehensive stakeholder process during 2010.

[132] ISO-NE Transmittal Letter at 9-10.

[133] ISO-NE Transmittal Letter at 10, 14.

settled going forward in the stakeholder process, a tie benefits value of 1,860 MW is just and reasonable for this final reconfiguration auction. There is no dispute that, as ISO-NE avers, the level of tie benefits ISO-NE proposes remains available from neighboring control areas. While the "as is" methodology was approved by the Commission for this reconfiguration auction, it is now clear that its application for the 2010/2011 commitment period would trigger operational concerns as highlighted by the testimonies of Mr. Brandien and Mr. Karl. Moreover, ISO-NE states that it has never been in a position to require 3,415 MW of emergency assistance and does not find that value to be realistic or achievable.[134]

77. Addressing ISO-NE's proposed tie benefits value, all parties are aware that the Commission previously approved this 1,860 MW value (offered under the "at criteria" methodology) for the primary and first reconfiguration auctions of the 2010/2011 commitment period.[135] While the allocation of these tie benefits among the Hydro Québec and New Brunswick and New York interfaces was a significant issue in the order establishing the Installed Capacity Requirement and related parameters for 2010/2011,[136] only NSTAR raised concerns over the actual total tie benefits value.[137] No other party raised concerns over ISO-NE's proposed tie benefits value in that proceeding and no

[134] ISO-NE Transmittal letter at 13; *see also* ISO-NE Answer at 16-17 (explaining cost savings to consumers, with a higher tie benefits value, is "extremely unlikely" because, with emergency transactions from New York priced at $999/MW-hour, "a single hour of shortage has the potential of offsetting the total potential capacity cost differential) .

[135] *ISO New England Inc.*, 121 FERC ¶ 61,250 (2007), *reh'g denied*, 123 FERC ¶ 61,129 (2008).

[136] *ISO New England Inc.*, 121 FERC ¶ 61,250 (2007).

[137] In that proceeding, NSTAR argued that the probabilistic methodology for calculating tie benefits should only apply to the New Brunswick and New York interfaces, while tie benefits over the Hydro Québec interconnection should be calculated using a deterministic methodology. The net effect of NSTAR's proposed methodology would have been to increase the total tie benefits value, and we countered that it would be "unreasonable to assume 2,250 MW of the total tie benefits are available to New England over its interconnections with neighboring control areas, because NSTAR's proposal double counts a portion of the tie benefits by failing to deduct the 1,400 MW of tie benefits attributed to HQ Capability Credits." NSTAR also raised concerns over the use of the "at criteria" rather than "as is" methodology in the primary auction proceeding.

comments were filed in the recent reconfiguration auction proceeding where ISO-NE found there was no need to update the tie benefits study.[138]

78. We agree with ISO-NE that it is unlikely that system conditions have changed significantly from the prior reconfiguration auction such that this value, which the Commission has recently accepted (and which no party challenged for the prior reconfiguration auction), is no longer valid. Commenters highlight the fact that ISO-NE states that any significant methodology changes at this time are premature, yet advocates adoption of the "at criteria" methodology for the last reconfiguration auction. However, since the "as is" methodology results in a tie benefits value that is not supported by any of the parties, it is not clear how any other value other than one calculated under an "at criteria" methodology (especially a value that the Commission previously has approved) would be valid pending additional stakeholder proceedings to address the tie benefit methodology.[139] We are not persuaded that this is an unjust and unreasonable approach. We also agree that the resulting 9.7 percent reserve margin with 1,860 MW of tie benefits is consistent with the historical level of reserves that have been required in New England.[140]

79. In addition to protesting ISO-NE's proposed tie benefits value, many of the commenters oppose to ISO-NE's proposed revision to section III.12.9 of Market Rule 1.

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[138] Docket No. ER09-640.

[139] ISO-NE did not support the "updated at criteria" analysis that ISO-NE states results in 1,525 MW of tie benefits for the 2010/2011 commitment period. NEPOOL contends that, by choosing not to present this value, ISO-NE made a policy decision consistent with NEPOOL's proposal. Because ISO-NE chose not to present this tie benefits value and all parties agree that the current methodology is inappropriate, we will not address this situation here.

[140] However, while ISO-NE points out that a 9.7% reserve margin is well below that of other control areas (e.g., the 18% margin required by NYSRC), we note that such a comparison is not truly relevant since the Installed Capacity Requirement for New England is calculated based on a probabilistic analysis employing a 0.1 LOLE. This probabilistic analysis considers expected loads, resource availability, and tie benefits. In New England, the Installed Capacity Requirement is not calculated as a function of reserve margin. As ISO-NE noted in the reserve margin gross-up proceeding, "The reserve margin is not a determinant of the [Installed Capacity Requirement]. That is, the [Installed Capacity Requirement] is not calculated by multiplying the peak load by one plus the reserve margin. Rather, the reserve margin is a product of the [Installed Capacity Requirement] calculation." ISO-NE, Transmittal Letter, Docket No. ER09-209, Attachment 3 at 7, 9 (Ethier testimony) (filed Oct. 31, 2008).

Specifically, many commenters oppose ISO-NE's proposal to use the "at criteria" methodology for all of the annual reconfiguration auctions because it is a permanent change. By comparison, the stakeholder-supported NEPOOL proposal revised the same section of the tariff but included language establishing a two-year sunset provision requiring ISO-NE to file market rule amendments, as necessary, applicable to the third reconfiguration auction for the 2012/2013 commitment period. NEPOOL's proposed revised language reads:

> [B]y December 31, 2010, the ISO shall review with Market Participants and, as necessary, file proposed market rule amendments reflecting a methodology for tie benefit calculations to apply to future third annual reconfiguration auctions beginning with the third annual reconfiguration auction for the 2012/2013 Capacity Commitment Period.[141]

Joint Commenters prefer the NEPOOL proposal but indicate that they would not object to a Commission order adopting the 1,860 MW value of tie benefits if it were explicitly adopted as an interim Market Rule, as NEPOOL proposed for its capped value.

80. While such language was not included in ISO-NE's proposed revisions to section III.12.9 of Market Rule 1, it is clear that ISO-NE plans to employ a stakeholder process during 2010 to address revising the tie benefit methodology for the last reconfiguration auction preceding a commitment period. In order to formalize this commitment, we will require ISO-NE to revise section III.12.9 of Market Rule 1, consistent with the language and timeline proffered by NEPOOL. We will not rule here on the deadline for compliance on the "Reserved Issues," however, since we agree with LIPA that they are outside the scope of the current proceeding.

81. Accordingly, we accept ISO-NE's proposed use of a 1,860 MW tie benefits value and consequent Installed Capacity Requirement and related values; however, we will require ISO-NE to revise section III.12.9 of Market Rule 1 concerning future potential market rule amendments to be consistent with NEPOOL's proposed language on this issue. The stakeholder process in this regard also should address the contention raised by NESCOE and other commenters that ISO-NE failed to provide the analysis requested by some stakeholders in connection with alternative proposals, with detailed explanations of reliability needs, estimated emergency events, and cost implications of options.[142]

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[141] NEPOOL Transmittal Letter at 8-9.

[142] NESCOE Comments at 5-6.

c. Tie Benefits Value: NEPOOL Proposal

82. NEPOOL's proposal also would revise section III.12.9 of Market Rule 1. NEPOOL proposes a cap on the allowed tie benefits value for the 2010/2011 and 2011/2012 commitment periods, resulting in a proposed tie benefits value of 2,286 MW. NEPOOL states that its proposal would retain the use of the "as is" methodology subject to this cap value. NEPOOL's revised tariff language would also require ISO-NE to review and file as necessary any revised tie benefit methodology to apply for all future final annual reconfiguration auctions commencing with the 2012/2013 commitment period. In support of this approach, NEPOOL notes that its approach is "more consistent" with the existing market rule that was approved by the Commission, ensures that tie benefits continue to meet the LOLE criterion, and represents a reasonable trade-off between "extra" reliability and extra cost to consumers. NEPOOL also argues that the Commission should consider that a broadly supported proposal as offered by NEPOOL is preferable to ISO-NE's proposal which drew little support.[143] In its supplemental comments, NEPOOL contends that because both proposals satisfy the relevant reliability criterion, the Commission must consider the inherent policy issues, including the stakeholder support and cost considerations of the NEPOOL proposal in making its decision.

83. It is significant that none of the commenters support the approach outlined by ISO-NE and that commenters argue that the "at criteria" assumption is too conservative, especially with the available capacity from the winter peaking Hydro Québec and Maritimes systems.[144] It is also noteworthy that none of the commenters critique the NEPOOL proposal, supporting it for reasons indicated previously, including its interim nature, its consideration of consumer impact, the fact that it represents a broad stakeholder consensus, the limited potential increase in OP 4 actions from adopting it, and the fact that it provides a target date for a revised permanent tie benefits rule. And NEPOOL makes the point that, because both proposals satisfy the relevant reliability criterion, the Commission must consider the inherent policy issues, including the stakeholder support and cost considerations of the NEPOOL proposal, in making its decision.[145] However, for the following reasons we find that the proposed NEPOOL Amendment has the following deficiencies.

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[143] NEPOOL's proposal was supported by a vote of 66.61% at the Participants Committee.

[144] *See, e.g.*, NSTAR Comments at 2; NESCOE Comments at 9.

[145] NEPOOL Supplemental Comments at 7, 9-10.

84. As noted previously, while NEPOOL's proposed tie benefits value may be valid, we find that NEPOOL has failed to demonstrate that fact in this proceeding. In addition to its concerns that the NEPOOL value represents a compromise proposal intended solely to receive stakeholder support, ISO-NE has raised several valid concerns over the origin of this value. For example, ISO-NE contends that the basis for this value was the result of a simulation case of the "LIPA Method" as reflected in a presentation made to the Power Supply Planning Committee. Specifically, ISO-NE states that these cases were developed by ISO-NE in order for LIPA to examine methodologies for allocating tie benefits to individual tie lines. ISO-NE states that NEPOOL provided no basis for selecting the "Case 1" methodology of the five cases presented, each of which reflect an "at criteria" methodology rather than "as is." Further, ISO-NE notes that none of the five cases represented a full calculation methodology and the "Case 1" that NEPOOL supports here was calculated using load forecast and resource availability data for the 2011/2012 rather than the appropriate 2010/2011 Capability Year. As such, ISO-NE contends that the value offered by NEPOOL bears "no relation" to study results that would be applicable to the 2010/2011 Capability Year. Lastly, ISO-NE contends that NEPOOL's application of a 10 percent discount on the tie benefits value to "assuage any ISO-NE concerns"[146] further demonstrates that the resulting figure is arbitrary.

85. NEPOOL contends that its proposal is superior to that offered by ISO-NE since it "is more consistent with the existing section III.12.9 of Market Rule 1" and "preserves the 'as is' method for calculating tie benefits."[147] However, since all of the parties here (and this Commission) agree that this "as is" methodology fails to provide an acceptable tie benefits value (in terms of reliability) for 2010/2011, such a position is not persuasive. Further, it appears that the NEPOOL value is actually derived from the results of a LIPA methodology that employs an "*at criteria*" rather than an "*as is*" assumption.[148] Potentially addressing this issue, Mass AG witness Plett states in his rebuttal testimony that "the proposal is to implement this 2286 MW cap, not use the LIPA methodology."[149] That statement is akin to saying that the value is correct regardless of the supporting methodology. Mr. Plett's statement also appears to directly conflict with NEPOOL's previously stated position to preserve the existing "as is" methodology and leads some credence to ISO-NE's position that the NEPOOL proposal seeks simply to lock in a broadly supported but poorly supported tie benefits cap for the next two capability years.

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[146] ISO-NE Transmittal Letter at 19 (citing Attachment I-1g at 3 (Mass AG, Powerpoint Presentation at Slide 3)).

[147] NEPOOL Transmittal Letter at 9.

[148] ISO-NE Transmittal Letter at 17 and ISO-NE Filing, Wong Test. at 34, 32-38).

[149] NEPOOL Filing, Plett Test. at 5.

86. We also note that ISO-NE raises legitimate concerns over NEPOOL's inherent adoption in the LIPA model of load forecast and resource availability data for the 2011/2012 rather than 2010/2011 capability year. Addressing this point, commenters state that "ISO-NE has not demonstrated that the difference in data between 2011/2012 and 2010/2011 is significant."[150] Further, Mass AG notes that if ISO-NE had concerns over this issue, "it could have assisted in refining the calculation."[151] However, we find that ISO-NE has committed to a remedy to the current situation that is just and reasonable until a revised methodology is developed through the current stakeholder process. While NEPOOL contends that the 10% discount included in their proposal addresses this capability year issue, we find that NEPOOL fails to offer a rigorous analysis to support the discount value or this related assertion.

87. The application of section 11.1.5 of the Participants Agreement, the jump ball provision, demonstrates that the stakeholder process did not ultimately support the ISO-sponsored proposal. In fact, the joint filing provides that the majority of the Participants Committee (66.61 percent) voted in favor of NEPOOL's alternative proposal, adopted from Mass AG's proposal. NEPOOL's proposal may strike a "reasonable balance" between reliability and costs to consumers.[152] However, a proposed tie benefits value, and consequently, the Installed Capacity Requirement and related values, cannot be based on such support alone. We find no merit in Mass AG's argument that "it is telling that the entire End User Sector, the interested parties that ultimately pay more for the cost of additional capacity" voted unanimously to support the NEPOOL proposal.[153] The NEPOOL Amendment supports a relatively higher tie benefits value, reducing the Installed Capacity Requirement and therefore the amount of capacity that is ultimately purchased for the commitment year. Given their obligation to purchase any additional capacity, end-users would not have an incentive to vote against the lower Installed Capacity Requirement established by the NEPOOL proposal. Similarly, we find no support for NEPOOL's proposal in NSTAR's assertion that "the determination of the tie benefits is as much art as it is science."[154]

88. In summary, ISO-NE states, and no party disputes, that application of the "as is" methodology could trigger operational concerns that would have serious, negative

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[150] Mass AG Protest at 6.

[151] Mass AG Protest at 7.

[152] Mass AG Protest at 5.

[153] Mass AG Protest at 7.

[154] NSTAR Comments at 5.

implications for reliability. While the NEPOOL proposal may be an improvement on the results from the "as is" methodology, NEPOOL has not adequately justified its proposal. For example, NEPOOL has not demonstrated how its proposal will avoid triggering the operational concerns identified in the testimonies of Mr. Brandien and Mr. Karl as to the "as is" methodology. For periods going forward, we are directing ISO-NE to consider a process to enable analysis of alternative proposals in a future market rule amendment. Further, as discussed above, we are directing ISO-NE to implement NEPOOL's proposed two-year sunset provision such that ISO-NE must employ a stakeholder process to address revising the tie benefit methodology applicable to the third reconfiguration auction for the 2012/2013 commitment period.

89. Accordingly, we will accept ISO-NE's proposed Installed Capacity Requirement and related values for use in the final FCM reconfiguration auction and the related proposed market rule change, subject to a condition, as just and reasonable and preferable.

D. Proration Issue

90. Consistent with their position in other proceedings, the PSEG Companies contend that, despite the reduction in the Local Sourcing Requirement in Connecticut for the 2010/2011 commitment period, PSEG and other companies supplying capacity in the Connecticut Zone have been prevented from prorating any megawatts associated with their resources. The PSEG Companies state that they have extensively discussed their concerns about this issue in comments in Docket ER10-186 addressing the results of ISO-NE's FCA for the third capacity auction, currently pending before the Commission. We note that this issue is pending in the current FCM Working Group stakeholder discussions (subject to a February 2010 filing with the Commission). In addition, the inability to prorate megawatts due to reliability concerns previously has been addressed by the Commission[155] and will be addressed for the third FCM commitment period should ISO-NE determine that resources in the NEMA/Boston Capacity Zone will be unable to prorate their megawatts.

The Commission orders:

(A) ISO-NE's proposed Installed Capacity Requirement, HQICCs, related values, and related tariff changes are hereby accepted, subject to condition, as discussed in the body of this order, effective on the sixty-first day after the date of submission, as requested.

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[155] *ISO New England Inc.*, 123 FERC ¶ 61,290 (2008).

(B) ISO-NE is hereby directed to submit a compliance filing within 30 days of the date of the issuance of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick Gerity, Counsel, Membership Subcommittee

DATE: February 26, 2010

RE: Request for Participants Committee Action on Application by Town of New Shoreham, RI

The Membership Subcommittee seeks Participants Committee ("NPC") action at the March 5, 2010 meeting on the application by the Town of New Shoreham, RI (more commonly known as "Block Island") for membership in NEPOOL as an End User Organization. The Town qualifies as an End User Organization pursuant to Section 1.21 of the Second Restated NEPOOL Agreement as it is "a governmental agency located in New England which does not meet the definition of Publicly Owned Entity."

The Membership Subcommittee, which approves applications for NEPOOL Membership by consensus, was not able to reach a consensus on the approval of the Town's Application because one member would not agree to approve the Application. That member articulated the following three reasons as the basis for his refusal to approve the Application without NPC action:

1. An alleged indirect relationship between the Town and Deepwater Wind (and then potentially through Related Person relationships, to First Wind and Boston Gen), which is developing an approximately 30 MW wind project just off the shores of Block Island. Other than an arrangement whereby Deepwater Wind agreed to subsidize the Town's costs in participating in an on-going proceeding before the RI PUC addressing the project, there is no evidence of any financial arrangement between the Town and Deepwater Wind.

2. Notwithstanding the absence of any AR Resources owned or controlled by the Town, Mr. Short's view that the Town's interests will better align with AR Sector members, and, therefore, the Town should be assigned to the AR Sector (or the Generation Sector) for governance purposes. The AR Sector representative participating in the Subcommittee meeting did not concur with this suggestion.

3. The precedent of small towns, with large generators in their town, joining as Governance Only End Users (and the implicit concern over the potential influence that the generator's interests might have over the participation in NEPOOL of any such town).

Because the Membership Subcommittee was unable to approve the Town's Application by consensus, the Subcommittee seeks Participants Committee action on the Application at the March 5, 2010 meeting.

Action on this matter could be achieved with the following form of resolution:

> RESOLVED, that the Participants Committee approves the membership Application of the Town of New Shoreham, Rhode Island ("Block Island") subject to the following conditions: (i) that the applicant sign and return the Standard Membership Conditions, Waivers and Reminders acceptance letter; (ii) that the ISO and NEPOOL counsel find the Application complete; and (iii) that the applicant execute an Indemnification Agreement.

SEAPORT HOTEL

FROM Points West via I-90:

Follow the Massachusetts Turnpike/Interstate 90 East to Exit 25 – South Boston. At the top of the ramp, bear left towards Seaport Boulevard. At the first set of lights, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage is located ahead on the right.

FROM Points South via I-93:

Heading northbound on I-93 towards Boston, take Exit 20, which will be immediately after Exit 18. Follow the signs to “I-90 East.” Take the first tunnel exit to "South Boston.” At the first set of lights at the top of the ramp, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be ahead on the right.

FROM Points North via I-93:

Heading southbound on Interstate 93 Boston, take Exit 23, Purchase Street and move into the left lane. At the top of the ramp, take a left turn onto the Evelyn Moakley Bridge/Seaport Boulevard. Follow Seaport Boulevard for approximately .8 miles, the Seaport Boulevard entrance to the Seaport Garage will be on the right, after the Seaport Boulevard/B Street intersection.

FROM Logan International Airport and Route 1A South:

Follow the signs towards I-90 West - Ted Williams Tunnel. Take the Ted Williams Tunnel to Exit 25. At the top of the ramp proceed straight onto B Street. Follow B Street to the end and take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be on your right.

PUBLIC TRANSPORTATION

The MBTA Silver Line Waterfront (SL1) provides service from the WTC Station to Logan International Airport terminals every 10 minutes during the weekday and every 15 minutes during the weekend. The Silver Line station is located adjacent to the hotel.

Seaport Boston is about 3 miles from Logan Airport, one of several hotels near the Boston Convention Center and a quick ride away from all Boston attractions. Taxis are readily available from the lobby of our hotel.

This scenic way to travel is a great way to avoid traffic. Hop on the water taxi shuttle at your terminal and enjoy the ride. The stop for pick up and drop off is at the Seaport World Trade Center, directly across the street from the Seaport hotel.