FINAL

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, December 6, 2013 at The Colonnade Hotel, Boston, MA pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present, including FERC Commissioner John Norris, his Legal Advisor, Andrew Weinstein, and representatives of the New England state regulators who joined the annual meeting.

APPROVAL OF NOVEMBER 8, 2013 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the November 8, 2013 meeting that were circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes, with a correction to the attendance, were unanimously approved.

CONSENT AGENDA

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved with abstentions by: BP, Brookfield, Energy America, Hess, and Integrys. Each of the representatives explained that they were abstaining because of Consent Agenda Item #1, which related to Net Commitment Period Compensation (NCPC) Local Second Contingency Protection Resource (LSCPR) Cost Allocation.

OP 12 REVISIONS (VOLTAGE SCHEDULING-RELATED REVISIONS)

Mr. Donald Gates, Chairman of the Reliability Committee, referred the Committee to the materials posted in advance of the meeting concerning revisions to Operating Procedure No. 12 (OP 12) and related appendices, which provided details regarding voltage and reactive control service. He summarized the changes briefly and then explained that the Reliability Committee had unanimously recommended Participants Committee support for the revisions at its November 19, 2013 meeting. He said that this matter would have been on the Consent Agenda but for the timing of the vote and notice of actions.

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

> RESOLVED, that the Participants Committee supports the proposed revisions to Operating Procedure No. 12, as recommended by the Reliability Committee at its November 19, 2013 meeting, together with such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

COMMENTS OF FERC COMMISSIONER JOHN R. NORRIS

Mr. Bowie welcomed FERC Commissioner John Norris to Boston and to the meeting and introduced him to the Committee. Commissioner Norris expressed appreciation to Mr. Bowie for his leadership role as Chairman of the Participants Committee over the past two years. He recalled his participation in the 2010 Summer Meeting in Connecticut, noting that it was good exposure to New England and the issues facing the region, which he said were notably different from those facing the Midwest region where he was from.

Commissioner Norris said that he participated in a Congressional oversight hearing the prior day entitled "*FERC's Role in the Changing Energy Landscape*," which was remarkably similar to the theme of the 2013 NEPOOL Annual Report, "*Today's Changing Landscape.*" He commented that the electric industry's landscape was changing at an unprecedented pace, largely attributable to new technology. He stated those changes included:

- the abundant supply of natural gas and low natural gas prices;
- expanded use of demand response and other demand side management measures;
- the use of new technology to measure and control the transmission grid; and
- the use of smart meters and innovative control systems for residential, commercial and industrial customers, which were all designed to permit wiser and more efficient use of energy.

He noted that there was big shift towards natural gas-fired generation across the country, but that other regions of the country did not face the same pipeline restrictions as New England. He explained that the need to build gas pipelines in New England was inevitable. He identified three steps that he recommended be taken before building new gas pipelines:

1. Assure full utilization of the current infrastructure. The FERC had held numerous gas-electric technical conferences over the previous several years, and recently issued revised Final Rules relating to communications between transmission and pipeline operators of confidential market information in order to maximize the utilization of current resources (Order No. 787).
2. Review scheduling patterns for the day-to-day operations of the electric and natural gas sectors. Natural gas operations were set on a national level and would be more difficult to change to accommodate the needs of the New England electric operations because of the broader ramifications in other areas of the country. The FERC encouraged and would welcome solutions tailored for New England's particular needs (e.g., dual-fuel capability).
3. Present to the FERC New England's plans to address the challenges to New England of limited gas transportation into the region so that the FERC could help enable New England to achieve its plans.

Commissioner Norris referred to the recently issued New England Governors Statement on the topic, stating that the collaboration among the states in New England reflected in that Statement was the right approach for New England to make broad decisions about its future and to address the limitations in available gas transportation capacity into the region. He also referred to the ISO pay-for-performance proposal, which he acknowledged was the topic of ongoing discussions, noting his understanding that the ISO was extremely concerned about capacity resources being available to produce energy and operating reserves when needed.

Focusing on the stakeholder process, Commissioner Norris emphasized that he thought it was extremely important for stakeholders to participate actively in the stakeholder process to consider changes to regional arrangements. He noted that changes in New England's market could have a broader impact on regional costs and reliability. In determining whether a filing to change those markets is just and reasonable, the FERC has looked very closely at whether consensus was achieved in the stakeholder process and, if not, why not. He expressed his view that the region would be well served arriving at broadly supported outcomes rather than relying on litigated outcomes that could be unpredictable and undesirable to the parties.

Transitioning to discussion of capacity market issues, Commissioner Norris noted that the FERC had held a technical conference in September to discuss the overall concern with whether the various capacity markets across the country were achieving their goals and, if not, what changes need to be made to those markets. He reported the FERC had extended the comment period into January 2014, noting the comments already received had been very helpful and informative, and he encouraged all interested parties to submit comments. He noted his concern that long-term capacity and other resources were being developed under the current construct and there was some urgency in his opinion in deciding whether to make adjustments to the current market designs or to fundamentally alter those designs. He stated that the FERC needed to know how severe the problems were with the current markets and whether the right market signals were being sent for the long-term investment in capacity needed in New England. He questioned whether New England's capacity surplus in recent years had masked market design issues and whether the capacity market was sending the necessary price signals for long-term supply. He stated that he did not anticipate the FERC would make a generic determination on these issues in the near future, but would continue to work on short-term issues on capacity, gas pipeline capacity, pay-for-performance proposals, and other short-term measures to address the immediate concerns.

With regard to transmission, he acknowledged that the FERC needed to address the ongoing return on equity (ROE) cases and send a clear signal regarding regulatory policy going forward. He shared his belief that a significant amount of transmission still needed to be built in New England and across the country, and that New England had the opportunity with new transmission to increase its utilization of renewables and hydro. He indicated his view that the FERC's job was to implement policies that were well-conceived to attract the level of capital needed to support the appropriate expansion and modernization of the distribution and transmission networks in order to maintain and improve reliability and efficiency. He concluded his comments on transmission by reviewing that the FERC last year updated its Return on Investment Policy for transmission investment to focus incentives in three areas: (1) deploying advanced technologies to make the electric grid more efficient; (2) reducing congestion to lower costs for consumers; and (3) reaching location-constrained resources with the transmission system. He stated that the FERC was ready to review applications seeking to apply those incentives to projects that achieve the desired goals. He indicated his belief that the FERC would articulate its ROE policy soon in order to guide future investment decisions.

Committee members then asked Commissioner Norris questions. Commissioner Norris agreed with a member that it would help if New England's market structure were simpler and more navigable and that the FERC would support movement in that direction. Regarding FERC Order 1000 and a request for a sense of the timing on the FERC's ruling on New England's compliance filings, Commissioner Norris stated his view that the FERC would be turning its attention to the Order 1000 compliance filings early in 2014 and that New England should be among those addressed earliest since the regional arrangements had already largely complied with Order 1000 requirements. He explained that the FERC wanted to complete its review of the initial Order 1000 filings so that it could turn its attention to Order 1000's interregional requirements. In response to a request as to whether FERC could take any action to help improve regional collaboration, Commissioner Norris indicated that the FERC strongly encouraged collaboration and would continue to signal that encouragement. He reiterated that the FERC was far more likely to accept a broadly supported proposal than one that arises out of a broken-down stakeholder process.

OTHER BUSINESS – NEW ENGLAND GOVERNORS STATEMENT

Ms. Heather Hunt, Executive Director, New England States Committee on Electricity (NESCOE), referred the Committee to the Governors Statement circulated and posted in advance of the meeting. She said that the Statement reflected the six New England Governors continued commitment to moving forward with regional energy infrastructure development. The Governors had observed the increasing interdependence between the electric and natural gas systems and the operational and associated cost issues. The Governors had also had the opportunity to assess various studies related to those topics. Ms. Hunt summarized that the Statement reflected the Governors' assessment that there was a need for increased investment in energy efficiency, renewable power, natural gas pipeline, and transmission. The commitments the Governors proposed to achieve a regional energy infrastructure included:

- Moving forward collaboratively and working jointly with the ISO and NESCOE on advancing a regional energy infrastructure initiative.
- Ensuring the costs of investment are shared appropriately across the states.
- Moving forward on a consensus basis, respecting individual states policies, statutes, and preferences, and ensuring that the policies of potential host states would be respected.
- Ensuring involvement of NEPOOL in the mechanics and processes going forward in order to share the Governors' preliminary thoughts and to seek additional ideas on objectives from NEPOOL.

Mr. Doot indicated that NESCOE had agreed to come back to the Committee at an appropriate point in the near future for discussion on process and substance, and Ms. Hunt committed to work with the NEPOOL Officers to ensure that happened.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie, ISO Chief Executive Officer, referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the November 8 meeting, circulated in advance of the meeting. Mr. Doot asked whether there was feedback received from the ISO Board on the Sector meetings held at the November 8 meeting and if there were recommendations to change the format at future meetings. Mr. van Welie reported that the Board enjoyed the interaction, liked the format of meeting with the individual Sectors as it proved to be informative to hear their individual views, and seemed to nurture increased dialogue, which was a good thing. He indicated that the ISO appreciated the Sectors providing the ISO with their questions in advance of the meetings as it permitted the Board to better prepare, allowing for more interactive and constructive dialogue.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the December COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing specifically on report highlights, he stated that in November: (i) natural gas prices were 51% higher and oil prices were 1.0% lower than October 2013 average values; (ii) Real-Time Hub locational marginal prices (LMPs) were up 25% from October 2013 averages; (iii) NCPC, totaling $5.3 million, was $2.9 million higher than October 2013 NCPC; (iv) first contingency payments, totaling $3.8 million, were $2.1 million higher than October's first contingency payments; (v) second contingency payments totaled $253,000, which was lower than the $461,000 in October; and (vi) voltage support payments totaled $1.2 million, up $1.1 million from October.

He reported that, based on the 50/50 and 90/10 load forecasts, the lowest Winter Operable Capacity Margin was projected for the week beginning January 18, 2014. He reviewed that, starting on December 9, the ISO would publish by 8:00 a.m. each day hourly forecasted demand for the current day and the next two days by reliability region/load zone.

Dr. Chadalavada provided an update on the Winter Reliability Program, stating that 56 Generators were participating in the Winter Fuel Procurement Program and all had submitted Monthly Fuel Inventory Surveys, with 43 having met or exceeded their required fuel inventory for December 1, and 13 still working through the verification process.

He then highlighted several operational observations, including:

- The amount of load clearing in the Day-Ahead Energy Market had increased in marked contrast to earlier in the year and past years.
- The Replacement Reserve trigger continued to work effectively for its intended purpose of pricing operator reliability actions.
- When resources generally needed for system reliability do not clear the Day-Ahead Energy Market, they may be committed in the Reserve Adequacy Analysis (RAA) process, contributing to uplift.
- Some resources in Northeastern Massachusetts (NEMA) had changed offer parameters (following consultation with the ISO Internal Market Monitor (IMM)) that may increase uplift for second contingency protection.
- The 2013 Regional System Plan was approved by the ISO Board on November 8.
- A draft interim photovoltaic (pv) forecast and pv interconnection issues would be discussed with the Distributed Generation Forecast Working Group on December 16.
- ICF International would report on Phase II of the Natural Gas Study at the December 18 Planning Advisory Committee (PAC) meeting.
- Results of the reliability determination analysis for a number of Non-Price Retirement Requests (NPRRs) would be presented at the December 19 Reliability Committee meeting.

Regarding the Forward Capacity Market, Dr. Chadalavada reported on the ISO's November 25 Exigent Circumstances filing to address the insufficient competition gap in the Market Rules as well as to modify the administrative price for existing capacity resources. He reported also that Non-Price Retirement Requests for Vermont Yankee had been approved and other requests were under study, and the study results would be presented at the December 19 Reliability Committee meeting. He stated that FCA8 would commence on February 3, 2014. He reported that stakeholder meetings on the capacity zone issue were ongoing, with the Reliability, Markets and Transmission Committees slated to vote on changes to Market Rule 1, Section 12 and OATT Attachment K at a joint December 17 meeting.

Committee members commented and asked clarifying questions on the COO presentation. In response to a member's request for more detailed information concerning Day-Ahead and Real-Time demands, Dr. Chadalavada committed to provide in future reports information as to what cleared over the peak-hour, as that information would be more informative of the commitments. In his report, Dr. Chadalavada had identified some uplift that was the result of a change in offer parameters by one of the Resources in the dispatch. Numerous members asked questioned seeking more specific details, to which Dr. Chadalavada demurred given the Information Policy restrictions on providing this information publicly. He did explain that the implications were for NEMA alone, and not system-wide, but changes in offer parameters by other Resources in New England could impact other areas of New England. A question was asked about the reason for the spike in Real-Time prices. Dr. Chadalavada responded that the spike was the function of high loads during colder weather, which caused the region to be deficient on Thirty-Minute Operating Reserves for a short period.

2013 NEPOOL ANNUAL REPORT

Mr. Doot referred the Committee to the 2013 NEPOOL Annual Report that was circulated at the meeting and posted on the NEPOOL website in advance of the meeting. He highlighted the emphasis in that Report on collaboration, and expressed the hope as the region works to address its many challenges that it would work to collaborate fully. He commented on the remarkable level of litigation activity in New England, with over 180 proceedings in which NEPOOL was either active or was monitoring, including six active appeals before the Federal Courts. He requested feedback on ways NEPOOL might be more successful in collaborating, reaching consensus, or at least compromising on issues that were preferable to address within the region rather than through order of the FERC or the courts following litigation. He expressed his personal appreciation to the NEPOOL Team for its efforts drafting and finalizing the NEPOOL Annual Report and encouraged stakeholder feedback on the Report.

ELECTION OF 2014 PARTICIPANTS COMMITTEE OFFICERS

Mr. Bowie referred the Committee to the slate of 2014 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. He expressed his gratitude for the Committee's support over the past two years of his service as Chairman, to NEPOOL Counsel and the NEPOOL Team for its support and service to NEPOOL, to the NEPOOL Officers for their wisdom and collegial advice, and to the ISO and the ISO Board for working through the issues and in serving jointly on the Joint Nominating Committee. He noted how fitting it was that both he and his good friend, Commissioner Michael Harrington, appointed as a Commissioner of the New Hampshire Public Utilities Commission (NHPUC) at the same time as he began his tenure as Participants Committee Chairman, were concluding their terms at the same time.

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

> RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2014 to the offices set forth opposite their names to serve until their successors are elected and qualified:

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

APPROVAL OF 2014 BUDGET FOR ESTIMATED PARTICIPANT EXPENSES

Mr. Joel Gordon, Budget & Finance Subcommittee (Subcommittee) Chairman, referred the Committee to the materials posted in advance of the meeting concerning the estimated budget for 2014 Participant Expenses (a copy of which is included as Attachment 3). He reported that, consistent with past practice, the Subcommittee worked with NEPOOL Counsel, the ISO and NEPOOL's Independent Financial Advisor to develop the 2014 Budget. He said that, at its November 18 teleconference, the Subcommittee discussed the proposed 2014 Budget and recommended its adoption without objection. During the Subcommittee's discussion, one member inquired about the need to continue credit insurance for those Market Participants not providing collateral under the Financial Assurance Policy. He explained that the ISO committed to look into that issue in 2014.

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

> RESOLVED, that the Participants Committee adopts the estimated budget for Participant Expenses for 2014 as presented at this meeting.

ISO NEW ENGLAND'S FCM PERFORMANCE INCENTIVES PROPOSAL

Ms. Allison DiGrande, Markets Committee Chairwoman, referred the Committee to the materials posted in advance of the meeting concerning ISO proposed revisions to the Forward Capacity Market (FCM) rules to implement its FCM Performance Incentives Proposal (PI Proposal) and related mitigation design. The ISO's PI Proposal was proposed to be implemented beginning with the Capacity Commitment Period associated with the ninth Forward Capacity Auction (FCA9) (beginning June 1, 2018). The PI Proposal would replace the existing FCM Shortage Event mechanism with a new "performance incentive" mechanism, resulting in capacity payments or charges to Resources that would be a combination of two components: (1) a base capacity payment; and (2) a performance payment or charge.

Ms. DiGrande reported that, during stakeholder discussions, the ISO agreed to two changes to an earlier version of the PI Proposal: (1) a so-called "stop loss" provision to accept an annual cap on aggregate performance charges; and (2) a phase in over time of the Performance Payment Rate (PPR) from the proposed rate of $5,455 per MWh, such that the PRR would initially be set at $2,000 per MWh and would climb over time to a rate supported by the ISO's theoretical calculation offered to support the PPR. She said that, over the preceding year, the Markets Committee, along with state regulators, reviewed the ISO's PI Proposal, with 13 amendments proposed to amend the ISO's PI Proposal at the November 13-14, 2013 Markets Committee meeting. One of the amendments received broad support at the Markets Committee (See Brookfield Amendment #3 below). The remaining amendments were not supported by the Markets Committee, and the once-amended main motion failed to receive sufficient support for recommendation by the Markets Committee. At the request of the ISO, the Markets Committee also voted, but failed to recommend Participants Committee support for, the ISO's unamended PI Proposal.

Mr. Bowie reviewed the process for Participants Committee consideration of the ISO FCM PI Proposal and referred the Committee to the list of 16 amendments reflected in the materials from NEPOOL Counsel circulated and posted in advance of the meeting. He explained that the Committee would review each of the amendments in the order reflected in those materials.

The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A to Market Rule 1 and Section 1.2.2 (Definitions) to implement the FCM Performance Incentives Proposal (FCM PI) and mitigation design, as proposed by ISO and as circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members then commented and asked clarifying questions on the PI Proposal. Publicly Owned Entity representatives objected to the Proposal because they viewed the proposed changes as unjustified in light of changes already made and/or efforts currently underway to provide enhancements to the Energy and Reserve Markets, and potentially imposing substantial additional costs on the region. One such Publicly Owned Entity representative expressed a preference to see how other initiatives already supported by NEPOOL and filed with the FERC played out and delivered before committing to broader, fundamental changes to the Forward Capacity Market.

Transmission Sector representatives objected to the Proposal, noting the fundament changes to unit configuration that would occur, expressing the view that units should not be penalized if they acted in accordance with ISO dispatch instructions. Further, Transmission representatives added that the PI Proposal should include an exemption for Resources unable to perform because of transmission limitations that were entirely outside of their control.

Generator representatives provided a variety of views. Members acknowledged that past operational events and deteriorating Resource performance factors supported the effort to enhance Resource performance incentives. One member expressed concern that, without some change, performance problems could increase, creating greater future problems. He urged support for the Proposal, but with a preference to provide a transmission outage exemption and to eliminate the Peak Energy Rent (PER) deduction. Several Generator representatives objected to the PI Proposal because it penalized Resources for following ISO dispatch direction, it did not have a transmission outage exemption (which they viewed as illogical given the ISO's involvement in scheduling all transmission outages), and it would not support new generation investment in the region.

In support, a Governance Only member stated the Proposal was an appropriate response to the significant inflection point in energy infrastructure, reliability, and market design, and would facilitate the kinds of technologies that were creating this inflection point and would make for a more efficient, lower cost, and more reliable system.

End Users expressed opposition to the Proposal. One member expressed appreciation to the ISO for its October 2012 White Paper, stating there was a lot to like about the design of PI, but objected to the Proposal because it did not provide an adequate basis upon which Demand Response could participate in the markets. Consumer Advocate End Users objected to the Proposal because it would apply risk to all resources 24/7, was untested, and would create an uncertain but much greater level of risk. They expressed a strong preference for a more modulated, less comprehensive approach. Other End User representatives objected to the Proposal because it was too risky for the market and, without adequate exemptions for Resources like energy efficiency and variable resources, could result in the region overpaying for capacity.

A NESCOE representative stated that NESCOE did not have a collective position on the ISO's PI Proposal or on any amended PI proposal.

The ISO representative expressed appreciation to the Committee for their engagement over the past year, noting that, based on stakeholder feedback, the ISO had incorporated the phase-in of the PPR and the annual "stop loss", and if the PI Proposal were to be implemented, the ISO would request continued feedback on improving it.

The Committee then proceeded to consider each of the proposed amendments.

***Brookfield Amendment #1*:** The Brookfield Energy Marketing (Brookfield) representative made a motion, which was duly seconded, to amend the main motion to provide an exemption for Intermittent Power Resources from the penalties associated with the PI Proposal (Brookfield Amendment #1).

The Committee commented on Brookfield Amendment #1. Some expressed support for the amendment because intermittent units were already subject to a major de-rating of their capacity value, and imposing a performance penalty would have no effect on intermittent unit performance, which was driven by factors (i.e., the weather) outside of owner/operator control. Opposition was expressed to the fact that such Resources were seeking an exemption from PI penalties but also wanted to maintain eligibility for bonus payments for performing better than their capacity rating. Others opposed Brookfield Amendment #1 in order to not upset the fact that, under the PI Proposal, the capacity market for the first time would define the same product for all sellers.

Dr. Robert Ethier stated the ISO did not support any exemptions and has done its best in developing the PI Proposal to create a level playing field so that all Market Participants would be treated the same and evaluated by the same criteria. He explained the ISO's reasoning, including: ensuring that, when offering into an auction, Resources offer based on the same set of performance expectations/requirements and reflecting their true characteristics, without adjustment for the benefits of any special treatment or special exemptions; preventing exemptions from undermining incentives; and preventing a shift in risk of the consequences of a failure to perform from a Resource that receives an exemption to everyone else.

Following final comments by Brookfield, the Committee considered and failed to approve Brookfield Amendment #1 by a show of hands.

***MMWEC Amendment #1*:** The MMWEC representative offered a motion, which was duly seconded, to amend the main motion to make Intermittent Resources exempt from the PI penalty and ineligible to receive a performance payment (MMWEC Amendment #1).

The Committee commented on the MMWEC Amendment #1. Much of the same support for, and opposition to, Brookfield Amendment #1 was also expressed in response to MMWEC Amendment #1, except for the fact that the Resources would neither receive penalties for failure to perform nor share in distributions of penalty revenues if they were to perform. The ISO stated that it could not support MMWEC Amendment #1 for reasons it had stated previously.

Following final comments by MMWEC, the Committee considered and failed to approve MMWEC Amendment #1 with a 53.33% Vote in favor (Generation – 2.14%; Transmission – 17.17%; Supplier – 1.56%; Alternative Resources – 4.56%; Publicly Owned Entity – 17.17%; and End User – 10.73%). (See Vote 1 on Attachment 2).

***Brookfield Amendment #2*:** The Brookfield representative offered a motion, which was duly seconded, to amend the main motion so as to exempt from PI non-performance penalties any External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols (Brookfield Amendment #2). The ISO stated that it could not support the amendment for the reasons stated previously.

The Committee considered and failed to approve Brookfield Amendment #2 by a show of hands.

***NU Amendment #1*:** The NU representative offered a motion, which was duly seconded, to amend the main motion in the manner identified by NU in the materials posted in advance of the meeting so as to exempt a Resource from FCM PI penalty if that Resource's inability to deliver energy or reserves during a scarcity condition was due to an outage or de-rate of a transmission facility in the New England Control Area (NU Amendment #1).

The Committee commented and asked clarifying questions. The Brookfield representative identified concerns with NU Amendment #1, highlighting, by way of examples, limitations in its exemptions, which would be addressed by Brookfield Amendment #3 to be subsequently offered for consideration. A Generator representative stated that the proposed transmission outage exemption was appropriate because it treated all the capacity sellers similarly. The NESCOE representative stated that, while the States did not have a collective position on the PI Proposal, they viewed these types of exemptions as appropriate in the sense that they were very structured and provided consumer savings by not imposing otherwise uncontrollable risk on generators. The ISO stated that, as with all of the exceptions, it opposed NU Amendment #1.

Following final comments by the NU representative, the Committee considered and approved NU Amendment #1 by a show of hands, with an opposition noted by NextEra.

***Brookfield Amendment #3*:** The Brookfield representative then offered a motion, which was seconded, to amend the once-amended main motion such that, if a Resource were subject to an ISO-imposed limit, the Resource would not be penalized for non-delivery of energy or reserves above that ISO-imposed restriction (Brookfield Amendment #3).

The Committee commented and asked clarifying questions on this amendment. In response to a question, the Brookfield representative explained that Brookfield Amendment #3, which had previously been recommended by the Markets Committee, was more expansive than NU Amendment #1 because Resources following dispatch instructions for any reason, including to avoid overloading a transmission line, would not be penalized. The ISO stated it could not support Brookfield Amendment #3 for reasons previously stated.

Following final comments by Brookfield, the Committee considered and failed to approve Brookfield Amendment #3 with a 56.84% Vote in favor (Generation – 7.36%; Transmission – 3.43%; Supplier – 14.71%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See Vote 2 on Attachment 2).

MMWEC Amendment #2**:** The MMWEC representative offered a motion, which was duly seconded, to amend the once-amended main motion so as: (i) to exempt from penalties under the PI Proposal (a) Import Capacity associated with contracts with the New York Power Authority (NYPA) and (b) Resources unable to perform or out-of-service due to a planned outage or loss of transmission; and (ii) to revise ISO-proposed Section III.13.7.2.5 to read as follows: "The ISO shall review the Performance Payment Rate in the stakeholder process ~~as needed~~ annually and shall file with the Commission a new Capacity Performance Rate if and as appropriate." (MMWEC Amendment #2).

The Committee commented and asked clarifying questions on the amendment. A NESCOE representative reported that the States would collectively oppose the amendment as they believed planned maintenance outages were a risk better borne by the generator. The ISO stated that it also opposed MMWEC Amendment #2.

The Committee considered and failed to approve MMWEC Amendment #2 by a show of hands.

NextEra Amendment: The NextEra representative offered a motion, which was duly seconded, to amend the once-amended main motion so as: (i) to set the PPR at $5,455 per MWh beginning with FCA9 (i.e., no phase-in); (ii) to provide a limited exemption for transmission-related outages; and (iii) to make a change to the monthly "stop loss" provisions (NextEra Amendment). To avoid confusion, the NextEra representative explained that the limited exemption for transmission-related outages included in the NextEra Amendment would replace in its entirety NU Amendment #1 already voted and approved.

The NESCOE representative noted the States' concern, previously expressed, that a PRR set at $5,455 per MWh would result in consumers having to pay more costs than the resulting benefits would justify as well as with NextEra's removal of the NU Amendment #1 language for transmission-related outages. He stated that, while the States did not have a collective position on the NextEra Amendment, were the NextEra Amendment to pass and be included in the PI Proposal, the States would oppose the PI Proposal.

The ISO stated that, while it supported the $5,455 MWh penalty amount, it had concluded that it was more appropriate to phase that value in to see how that design worked, and therefore would not support the NextEra Amendment.

Following final comments, the Committee considered and failed to approve the NextEra Amendment by a show of hands.

***EquiPower Amendment*:** The EquiPower Resources Management (EquiPower) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to permit an existing Resource to submit a Static De-List Bid for up to the megawatt amount that the Market Participant expected may not be physically available due to reductions in ratings as measured by EFORd multiplied by summer Qualified Capacity at 90 degrees (EquiPower Amendment).

The NESCOE representative indicated that the States opposed the amendment for the reasons identified at the Markets Committee meeting.

The ISO stated that it could not support the EquiPower Amendment because it believed it appropriate for Resources to submit price and megawatt pairs for each megawatt for which they were qualified.

The Committee considered and failed to approve the EquiPower Amendment by a show of hands.

***NU Amendment #2*:** The NU member offered a motion, which was duly seconded, to amend the once-amended main motion so as to eliminate changes in that Proposal to the current FCM performance rules for passive demand resources (NU Amendment #2).

An End User representative stated support for the amendment and expressed appreciation to NU for introducing it. The ISO stated it could not support the amendment.

The Committee considered and failed to approve NU Amendment #2 by a show of hands.

***NU Amendment #3*:** The NU member then offered a motion, which was duly seconded, to amend the once-amended main motion by inserting the current Market Rule provisions in the ISO-proposed Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource's Capacity Performance Payment under FCM PI (NU Amendment #3).

The ISO stated it could not support the amendment because it would fundamentally undermine the PI design.

The Committee considered and failed to approve NU Amendment #3 by a show of hands.

***PSEG Amendment*:** The PSEG Energy Resources & Trade (PSEG) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to set the FCA9 Starting Price at $22/kW-month.

Generator representatives expressed support for the amendment, insisting that there would be no downside to increasing the FCA Starting Price and the increase would be helpful to the market. The NESCOE representative indicated that the States had not had an opportunity to discuss the PSEG Amendment, nor had there been any prior discussion in the stakeholder process, and suggested that it was important for those discussions to take place before consideration of the PSEG Amendment.

The ISO stated that it did not support the PSEG Amendment at that time, but recognized the need to periodically evaluate the FCA Starting Price and urged that there be process around that issue. The ISO noted its plans and expectation for presentation and discussion of a sloped demand curve at the following month's Markets Committee meeting, and suggested that, based on feedback to be received, it would make a determination as to how to proceed for FCA9.

Following final comments by the PSEG representative, the Committee considered and failed to approve the PSEG Amendment by a show of hands.

Dominion Alternative**:** The Dominion Energy Marketing (Dominion) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to replace the ISO's PI Proposal with an EFORd pay-for-performance approach and maintain the enhanced Shortage Event penalty mechanism recently accepted by the FERC (effective as of November 3, 2013) (together, the Dominion Alternative). The ISO stated that it did not view this Amendment to be an improvement over the status quo, and as a result could not support, the Dominion Alternative.

The Committee then considered and failed to approve the Dominion Alternative by a show of hands.

NRG Alternative**:** The NRG Power Marketing (NRG) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to replace the ISO's proposed FCM PI Tariff revisions, as proposed to be amended by the previously approved motion to amend, with Market Rule revisions that: (1) would increase the Reserve Constraint Penalty Factors (RCPF) for System Thirty-Minute Operating Reserves (TMOR) from $500 to $1,000 and for System Ten Minute Non Spinning Reserves (TMNSR) from $850 to $1,500; and (2) would replace the then effective "Shortage Event" mechanism with a mechanism to measure performance using an EFORp 'availability' metric that would impose charges or provide credits to Resources based on their availability in pre-defined peak hours during the Capacity Commitment Period (the NRG Alternative).

The Committee commented and asked clarifying questions on the NRG Alternative. Members in support expressed their view that the NRG Alternative was a major improvement over the PI Proposal because it was more likely to incent new investment, more appropriately reflected the actual capabilities of existing Resources as relied on in setting the region's capacity requirements, and placed stronger incentives in the energy market. One member opposing the NRG Alternative explained that while his company was supportive of improving energy pricing, it could not support the NRG Alternative because it would replace the PI Proposal with something that would not address all the performance issues.

In response to questions, the NRG representative clarified that the cap on the availability penalties related to a Force Majeure event would only be calculated from the time of the event going forward and could not be used to mitigate penalties incurred prior to the event. The NRG representative also explained that, as with the then-current FCM rules, there would not be an explicit obligation to cover for the loss of a Resource caused by a catastrophic event. Rather, each owner would be expected to weigh its alternatives and limit its losses as appropriate by measuring the cost of its alternatives against the availability penalties, capped at 20%, to be assessed.

The NESCOE representative stated that the States did not have a collective opinion on the NRG Alternative. A representative of the Connecticut Department of Energy and Environmental Protection expressed support for the Alternative because it would improve price formation, would result in market rather than administrative response by units, and ultimately was an appropriate and preferable alternative to what the agency believed to be a deeply flawed ISO PI Proposal.

The NextEra member highlighted that the NextEra Amendment, which had not been supported by the Committee, was intended similarly to bring the right incentives into the market, and believed that, absent full Commission approval of that amendment, the ISO PI Proposal should be rejected in its entirety and Equivalent Forced Outage Rate mechanisms considered. She stated that NextEra would abstain on the NRG Alternative largely due to concerns with the Alternative's details, but stressed the importance of sending a signal to the FERC that an alternative was the right choice for the region at that time, with the understanding that details going forward would be worked out.

Other members who expressed support for the NRG Alternative explained that it was a rational approach, taking measured steps to address evolving regional challenges in the proper market context, and identifying and implementing further incremental changes with the benefit of experience rather than waiting until June 1, 2018 (the start of the Capacity Commitment Period associated with FCA9) as proposed by the ISO. They further expressed support for the NRG Alternative because the region could minimize the large anticipated increase in capacity prices under the PI Proposal, while the benefits of other initiatives could be assessed. Others attributed their support to an increased confidence that the changes proposed by the NRG Alternative could be hedged in the market place.

Some members, while acknowledging that many elements of the NRG Alternative had been discussed during the stakeholder process, expressed concern with the swiftness with which the NRG Alternative had eventually evolved. They indicated that, while they found the Alternative preferable to the ISO Proposal, they needed additional time to consider whether they could support the Alternative and would therefore abstain when asked. Others expressed the view that, had the ISO Proposal programmatically dealt with prior concerns raised, they would have preferred the incentives provided by the ISO Proposal. Absent those changes, however, these members preferred the NRG Alternative and looked forward to working through its details.

The ISO identified its concerns with the NRG Alternative, noting: (1) the Alternative, relative to what was then in place in the Tariff, would take a step backwards with respect to incenting Resource performance; (2) the Alternative would not resolve the "zombie resource" or "money for nothing" problems so characterized; and (3) the ISO had not had an opportunity to fully consider the latest changes proposed by the NRG Alternative which had just been presented to the Committee.

Following final comments by NRG, the Committee considered and approved the NRG Alternative with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%; Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See Vote 3 on Attachment 2).

***NRG Amendment #2*:** The NRG member offered a motion, which was duly seconded, to amend further the NRG Alternative, as reflected in the twice-amended main motion, so as to eliminate the FCM PER deduction (NRG Amendment #2).

The Committee commented and asked clarifying questions on the amendment. An End User representative expressed support, noting that he did not believe the PER deduction as then structured was a hedge for load because it was poorly designed to do that, was arbitrary, had unwanted effects on Demand Response (DR) and other Resources not dispatched within those hours, and did not provide a hedge against scarcity pricing. An AR representative echoed those sentiments, indicated his view that the energy market was already sufficiently mitigated, and indicated that he would support the elimination of the PER deduction. A Transmission member expressed opposition to eliminating PER, indicating that it was a hedge for load, as well as a protection against the exercise of market power. The NESCOE representative indicated support for the view that the PER deduction could result in consumer savings but also support for reconsidering the mechanism. He went on to indicate that the States would, however, collectively oppose the elimination of the PER deduction and NRG Amendment #2.

The ISO indicated that, in the context of its PI Proposal, it would support discussion about PER and how it worked in conjunction with PI, but with PI stripped out of the Proposal before the Committee, the ISO could not support NRG Amendment #2.

Following final comments by NRG, the Committee considered and failed to approve NRG Amendment #2 with a 44.01% Vote in favor (Generation – 17.17%; Transmission – 0%; Supplier – 17.17%; Alternative Resources – 6.55%; Publicly Owned Entity – 0%; and End User – 3.12%). (See Vote 4 on Attachment 2).

***GDF SUEZ Amendment*:** The GDF SUEZ Energy Marketing North America (GDF SUEZ) representative offered a motion, which was duly seconded, to amend the twice-amended main motion so as to modify the PER deduction to avoid potential outcomes where Resources would effectively operate a loss when called on by the ISO to provide generation, operating reserves or regulation services in Real-Time (GDF SUEZ Amendment).

Mr. Doot clarified for the Committee that were this Amendment to pass, NEPOOL would make the necessary conforming changes to the Market Rules under the twice-amended main motion. The ISO said that it did not support the GDF SUEZ Amendment.

Following final comments by GDF SUEZ, the Committee considered and failed to approve the GDF SUEZ Amendment by a show of hands, with the vote being approximately the same as the roll call vote taken on NRG Amendment #2.

NRG Amendment #3**:** The NRG representative offered a motion, which was seconded, to amend further the NRG Alternative, as reflected in the twice-amended main motion, so as to revise the current Market Rules: (i) to permit offer prices for existing Resources (de-list bids) based on "long-run average costs" rather than "net risk-adjusted going-forward costs"; (ii) to establish the Dynamic De-List Bid threshold at 80% of the Offer Review Trigger Price of a combustion turbine; and (iii) to enable Existing Resources with IMM-approved offers above the Dynamic-List Bid threshold to participate in the auction at prices below the IMM-approved price (NRG Amendment #3).

The NESCOE representative stated that, while the States did not at that time have a collective position, he would recommend opposition to this Amendment. A Publicly Owned Entity representative stated that, while members of his Sector liked certain elements of NRG Amendment #3, there were certain parts they could not support and therefore would oppose the Amendment as a package. A Supplier representative expressed support, noting that in the current market design all new Resources were required to bid at their long run average cost, but all existing Resources were prohibited to bid at their long run average cost, creating a gap causing a lot of dislocation in the current capacity market. He stated that gap would not get fixed until all Resources were allowed to offer based on their commercial business interests, and not subject to administratively set caps on their potential profitability. An End User representative expressed opposition to the Amendment, acknowledging the disconnect between the way business people view risk and rules resulting in bidding at an administratively set number, and the need to address that disconnect, but questioning the suitability of NRG Amendment #3 to correctly address that issue. The ISO stated that it could not support this Amendment.

The Committee then considered and failed to approve NRG Amendment #3 by a show of hands, with support coming generally from generators and some suppliers, and opposition or abstentions by others.

Twice-Amended Main Motion (i.e., the NRG Alternative)**:** The Committee then considered and approved the twice-amended main motion (i.e., the NRG Alternative) with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%; Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See Vote 3 on Attachment 2).

Unamended ISO Proposal**:** The ISO requested consideration and a vote on its unamended ISO Proposal, as offered and seconded at the beginning of the discussion. A Transmission representative expressed support for the unamended ISO Proposal stating that, when New England decided to establish a capacity market, the region decided that it was a better way to go rather than a pure energy market with higher Real-Time energy prices, and once that decision was made, the goal was to try to mimic the results achieved from a pure, uncapped energy market, which was what the ISO had done and reflected in its Proposal. He encouraged members to re-read the ISO's October 2012 White Paper and note that the ISO was appropriately recognizing the different value of flexible versus inflexible Resources in trying to get to the point where more flexible Resources would get paid more, and less flexible Resources, less.

The Committee considered and failed to approve the ISO's unamended FCM PI Proposal with a 10.28% Vote in favor (Generation – 2.86%; Transmission – 2.86%; Supplier – 1.29%; Alternative Resources – 2.66%; Publicly Owned Entity – 0%; and End User – 0.61%). (See Vote 5 on Attachment 2).

With regard to the timing of the filing of the ISO's Proposal and the NRG Alternative under the jump ball provisions of the Participants Agreement, Mr. Hepper stated that the filing would not be submitted before December 31, and that ISO and NEPOOL Counsel would work together to identify a date for the FERC filing in January.

FCM PI-RELATED FINANCIAL ASSURANCE POLICY REVISIONS

Mr. Doot referred the Committee to the materials posted in advance of the meeting regarding revisions to the ISO Financial Assurance Policy (FAP) to establish financial assurance requirements under the FCM PI Proposal. He explained that the revisions would be made if the PI Proposal was implemented without change in relevant respect, and with the understanding that the FA Changes and any proposed revisions thereto would be re-presented to NEPOOL for subsequent consideration in the Participant Processes if the Commission required changes to the underlying FCM PI Proposal that impact the financial assurance requirements. Mr. Gordon reported that the Subcommittee recommended that, if the FCM PI Proposal were to be implemented, the FA Changes also be implemented to appropriately collateralize the Pool to protect against potential defaults from potential PI penalties resulting from the revised market design.

The following motion was duly made and seconded:

> RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO-NE Financial Assurance Policy to establish financial assurance requirements under the FCM Performance Incentives (PI) Proposal (FA Changes), as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve; it being understood that a vote in favor of this resolution reflects solely support for the FA Changes, as appropriate, if and only if the FCM PI Proposal is approved and implemented as proposed by the ISO, and is without prejudice to any position taken by a Participant(s) on the underlying FCM PI Proposal, and with the further

> understanding that the FA Changes and any proposed revisions thereto shall be re-presented to NEPOOL for subsequent consideration in the Participants Process if the Commission requires changes to the underlying FCM PI Proposal that impact the financial assurance requirements.

A representative of members that provide energy efficiency in the region reported that he raised questions with the ISO Credit Department regarding how the FA Changes would work for his clients. Due to the extreme uncertainty on the PI Proposal, he explained that they would not seek an amendment at that time, but depending on the FERC's response to the jump ball filing, may seek changes to the FAP at a future time.

The Committee considered and approved the motion with oppositions noted by: CSG, NHOCA, Small DG Group (AR), Small LR Group (AR), UCS, Utility Services, and VEIC; and abstentions by: Brookfield, CSC, CTOCC, Environment Northeast, First Wind, Kimberly-Clark, LIPA, Linde, NextEra, Praxair, NGrid, Provisional LR Group (AR), Small RG Group (AR), UI, and Vitol.

IMM-PROPOSED ORTP FOR FCA9

Ms. DiGrande referred the Committee to the materials posted in advance of the meeting regarding IMM-proposed revisions to Market Rule 1, Appendix A relating to the Offer Review Trigger Prices (ORTP) for FCA9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation (ORTP Changes). She reported that, at its November 13-14, 2013 meeting, the Markets Committee considered and failed to recommend Participants Committee support for the IMM-proposed ORTP Changes with a 16.57% Vote in favor. Prior to the Markets Committee's vote on the IMM's ORTP Changes, four motions to amend the main motion were considered (two failed and two were supported). The twice-amended main motion (as amended by EnerNOC and EMI) was considered by the Markets Committee but failed with a 56.24% Vote in favor.

The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A regarding Offer Review Trigger Prices (ORTP) for the ninth Forward Capacity Auction (FCA9), the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation, as proposed by the ISO's Internal Market Monitor (IMM) and circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

The Committee members then commented and asked clarifying questions on the motion. NHPUC Commissioner Harrington expressed continued support for the NESCOE filing at the FERC, which sought an exemption for renewables from the ORTP and that consideration of ORTPs should be tied to state renewable portfolio standard (RPS) laws so there was an evolving cap that would grow with RSP requirements but there would not be an unlimited amount of renewables that would be exempt from the review process. He argued that all wind resources needed a properly established ORTP, not a zero price. The NEPGA representative agreed with Commissioner Harrington's comments. The NESCOE representative explained that, while the States would collectively support the EnerNOC Amendment, the majority of the States would oppose the NextEra Amendment, and the States would collectively oppose the Exelon Amendment.

The NextEra representative stated NextEra would offer an amendment regarding the IMM's proposed ORTP for on-shore wind, explaining that it sought a sound, well-analyzed, reasoned economic analysis for ORTPs, rather than policy arguments. Another generator representative disagreed, arguing that policy element was extremely important as it was primarily wind projects that were signing rate-based, state-supported contracts and the purpose of the Minimum Offer Price construct was to have the IMM review the projected costs and revenues and make sure that any out-of-market revenues were not included. Another generator representative commented that the ISO spent considerable time conducting the Wind Integration Study and the numbers were properly inputted and well-supported from government sources and the results were what they were. An AR representative stated the ORTPs were based on appropriate analysis, and not on policy, and he would support the ISO's IMM-proposed changes.

EnerNOC Amendment: The EnerNOC representative offered a motion, which was duly seconded, to amend the main motion (EnerNOC Amendment), so as to add a new Section III.13.1.4.2.4 to Market Rule 1, as follows:

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

The ISO stated that it could not support the motion to amend for the reasons outlined in its memorandum presented to the Markets Committee and posted with the meeting materials in advance of this meeting.

The Committee considered and approved the EnerNOC Amendment with a 75.97% Vote in favor (Generation – 10.2%; Transmission – 17.17%; Supplier – 17.17%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See Vote 6 on Attachment 2).

***NextEra On-Shore Wind Amendment*:** The NextEra representative offered a motion, which was duly seconded, to amend the once-amended main motion (as amended by the EnerNOC Amendment) so as to set the ORTP for on-shore wind at $8.53/kW-month (NextEra Amendment).

Members opposing the NextEra Amendment commented that the IMM's analysis was correct and the data chosen in NextEra's analysis had a number of problems as that data did not take into account the curtailments in many areas of the region because of transmission constraints, particularly in Maine because of the Maine Power Reliability Program, which would lower the capacity factors being experienced there. An AR representative disagreed with the argument that the ORTP level needed to be set at a very high number. He explained that the FERC required the IMM to set a level that was appropriate for each technology and that was exactly what the IMM, with input from wind developers, have attempted to do here.

In support of the NextEra Amendment, a NHPUC representative stated NH believed that setting an ORTP at zero was inconsistent with the goal to protect the market against buyer-side market power and, without this protection, NH was concerned that the efficiency of the market would be harmed to the long run detriment of the consumers. A member commented that the IMM's proposed ORTP for on-shore wind would potentially disrupt the market, and the unwillingness of the IMM to further evaluate and reconsider its proposal did not make sense. He encouraged support for the NextEra Amendment.

The ISO stated that it could not support the NextEra amendment for the reasons previously indicated.

Following final comments by NextEra, the Committee considered and failed to approve the NextEra Amendment by a show of hands.

***EMI Off-Shore Wind Amendment*:** The Energy Management Inc. (EMI) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to set the ORTP for off-shore wind at $0.00 kW-month (EMI Off-Shore Wind Amendment).

The MA DPU representative stated the MA DPU was in favor of the EMI Amendment and EMI had shown sufficient documentation to prove that the ORTP for off-shore wind projects should be set at zero and should be in place for FCA8. A member of the Transmission Sector spoke in support of the Amendment and urged that an ORTP for off-shore wind be calculated and filed with the FERC, rather than simply set at the FCA Starting Price.

The ISO indicated that it continued to oppose the Amendment for the reasons indicated at the Markets Committee.

The Committee considered and approved the EMI Off-Shore Wind Amendment by a show of hands.

***Exelon Amendment*:** The Exelon representative explained that Exelon had circulated an amendment that it offered at the Markets Committee, but given the outcome at the Markets Committee and in the interest of time, with the understanding that it had satisfied the stakeholder process, would rely on the Markets Committee vote and not seek a vote at the Participants Committee.

***Twice-Amended Main Motion*:** The Committee then considered the twice-amended main motion (as amended by the EnerNOC and EMI Off-Shore Wind Amendments). The twice-amended main motion was voted and failed with a 54.94% Vote in favor (Generation – 2.14%; Transmission – 17.17%; Supplier – 4.29%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (<u>See</u> Vote 7 on Attachment 2).

***Unamended ISO ORTP Proposal*:** At the request of the ISO, the Committee considered and failed to approve the ISO's unamended ORTP Proposal by a show of hands.

ISO NOVEMBER 25, 2013 EXIGENT CIRCUMSTANCES FILING

Mr. Doot reported that, as there was insufficient time to review the ISO's November 25 Exigent Circumstances filing proposing FCM Administrative Pricing Rule Changes given the lateness of the hour and meeting space time restrictions, a special teleconference meeting would be scheduled for December 10 to review with members that filing and NEPOOL's response.

LITIGATION REPORT

Mr. Doot referred the Committee to the December 4 Litigation Report that had been posted in advance of the meeting. He encouraged anyone with comments or questions on the Report to please contact him or any of NEPOOL's Counsel.

OTHER BUSINESS

Mr. Doot referred the Committee to the NEPOOL calendar for December. He reported that the next regularly-scheduled meeting of the Participants Committee would be January 10, 2014 at the Seaport Hotel in the Seaport Ballroom in Boston.

There being no further business, the meeting adjourned at 4:35 p.m.

Respectfully submitted,

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David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Bangor Hydro-Electric Company	Transmission		Stacy Dimou	Joe Staszowski (A9)
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned		Dave Cavanaugh	
Brookfield Energy Marketing / Cross-Sound Cable	Supplier	Aleksandar Mitreski	Jose Rotger	
Calpine Energy Services, LP	Supplier	John Flumerfelt		
Central Maine Power Company (CMP)	Transmission	Eric Stinneford (tel)		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Cianbro Companies	End User			Don Sipe (A9, A10)
Citigroup Energy Inc.	Supplier	Barry Trayers (tel)		
Competitive Energy Services, LLC	Supplier			Glenn Poole; Dennis Duffy (A9)
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User	Elin Katz	Joe Rosenthal	Paul Peterson
Corinth Wood Pellets LLC	End User			Don Sipe (A9, A10)
Conservation Law Foundation (CLF)	End User		Naim Jonathan Peress	
Conservation Services Group (CSG)	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart (tel)		
Dragon Products Company LLC	End User			Don Sipe (A9, A10)
DR Power	Supplier	Jerry Tudan		
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User			Don Sipe (A9, A10)
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy	Greg Geller	
Entergy Nuclear Power Marketing Inc.	Generation		Chad Cooper	
Environment Northeast	End User	Mike Henry (tel)		
EquiPower Resources Management, LLC	Generation	Jim Ginnetti	William Fowler	
Essential Power, LLC	Generation	M.Q. Riding		
Exelon Generation Company	Supplier	Steve Kirk	William Fowler	
First Wind Energy Marketing, Inc.	AR	John Keene		Bob Stein
Food City, Inc.	End User			Don Sipe (A9, A10)
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier		Robert Stein	
Hardwood Products Company	End User			Don Sipe (A9, A10)
Harvard Dedicated Energy Limited	End User	Mary Smith		
Hess Corporation	Supplier			Nancy Chafetz
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	Donald Sipe
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned		Brian Beauregard	
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		
IPR-GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		John Flumerfelt
Ipswich Municipal Light Department	Publicly Owned		Gary Will	

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Kimberly-Clark Corporation	Supplier			Vicki Karandrikas (tel)
LaBree’s Inc.	End User			Don Sipe (A9, A10)
Linde Energy Services	Supplier			Vicki Karandrikas (tel)
Littleton (MA) Electric Light & Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny (tel)	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Public Advocate Office (ME OPA)	End User		Tim Schneider	Paul Peterson
Maine Skiing, Inc.	End User	Donald Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden’s Inc.	End User			Don Sipe (A9, A10)
Mass. Attorney General's Office	End User	Fred Plett	Christina Belew	Jesse Reyes
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
Millennium Power Partners	Generation		Ken Dell Orto	
MoArk, LLC	End User			Don Sipe (A9, A10)
New England Power Company (National Grid)	Transmission	Timothy Brennan		Tim Martin
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NU / NSTAR	Transmission	James Daly	Calvin Bowie	Joe Staszowski
NRG Power Marketing, Inc.	Generation	Peter Fuller		
PalletOne of Maine	End User			Don Sipe (A9, A10)
Pascoag Utility District	Publicly Owned			
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cynthia Arcate		Paul Peterson
PPL EnergyPlus, LC	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Vicki Karandrikas (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member - Load Response Sub-Sector	AR	Brad Swalwell (tel)		
Provisional Group Member	Transmission	Steve Conant		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Rumford Paper Company	End User	Donald Sipe		
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User			Don Sipe (A9, A10)
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
St. Anselm College	End User			Don Sipe (A9, A10)
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium (TEC)	End User		Mary Smith	
TransCanada Power Marketing Ltd.	Generation		Mike Hachey	P. Fuller (NRG Amend 1)
Union of Concerned Scientists (UCS)	End User	Paul Peterson		

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
United Illuminating Company (UI)	Transmission		Alan Trotta	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny (tel)		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori		Mark Sciarrotta
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		Brian Forshaw
Verso Maine Energy LLC	Generation	Glenn Poole	David Norman	
Vitol, Inc.	Supplier	Joe Wadsworth		Jose Rotger
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
Wallingford DPU Electric Division	Publicly Owned	Dave Cavanaugh		
Wellesley Municipal Light Plant	Publicly Owned	Dave Cavanaugh		
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital, The	End User			Don Sipe (A9, A10)
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
Z-TECH LLC	End User			Don Sipe (A9, A10)

ATTACHMENT 2

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR	VOTE 1	VOTE 2	VOTE 3	VOTE 4	VOTE 5	VOTE 6	VOTE 7
GENERATION	2.15	7.36	14.71	17.17	2.86	10.30	2.15
TRANSMISSION	17.17	3.43	13.73	0.000	2.86	17.17	17.17
SUPPLIER	1.56	14.71	15.45	17.17	1.29	17.17	4.29
AR	4.56	14.17	3.37	6.55	2.66	14.17	14.17
PUBLICLY OWNED ENTITY	17.17	0.00	17.17	0.000	0.000	0.000	0.000
END USER	10.73	17.17	15.85	3.12	0.61	17.17	17.17
% IN FAVOR	53.33	56.84	80.28	44.00	10.28	75.97	54.94

GENERATION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Dominion Energy Marketing, Inc.	A	F	F	F	O	A	
Entergy Nuclear Power Marketing LLC	A	A	A	F	O	A	O
EquiPower Resources Management, LLC	O	O	A	F	O	O	O
Essential Power, LLC	A	O	F	F	O	A	O
GDF SUEZ Energy Marketing North America	O	O	O	F	F	O	O
Generation Group Member	F	F	F	F	0.5	F	F
Millennium Power Partners	O	A	A	F	A	A	O
NextEra Energy Resources, LLC	O	O	A	F	O	A	O
NRG Power Marketing, LLC	O	A	F	F	O	F	O
TransCanada Power Marketing Ltd.	O	A	F				
Verso Maine Energy LLC	O	F	F	F	O	F	A
IN FAVOR (F)	1	3	6	10	1.5	3	1
OPPOSED (O)	7	4	1	0	7.5	2	7
TOTAL VOTES	8	7	7	10	9	5	8
ABSTENTIONS (A)	3	4	4	0	1	5	1

TRANSMISSION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Bangor Hydro-Electric Co.	F	A	F	A	O	F	A
Central Maine Power Co.	F	O	A	O	O	A	F
New England Power Co.	F	O	O	O	F	F	F
The United Illuminating Co.	F	F	F	O	O	F	F
NU /NSTAR	F	O	F	O	O	F	A
Vermont Electric Power Co.	A	O	F	O	O	F	F
IN FAVOR (F)	5	1	4	0	1	5	4
OPPOSED (O)	0	4	1	5	5	0	0
TOTAL VOTES	5	5	5	5	6	5	4
ABSTENTIONS (A)	1	1	1	1	0	1	2

ALTERNATIVE RESOURCES

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Renewable Generation							
First Wind Energy Marketing	O	F	O	F	F	F	F
Small RG Group Member	A	F	F	F	O	A	A
Distributed Generation							
Conservation Services Group	A	F	A	O	O	F	F
Small DG Group Member	A	F	A	O	O	F	F
Load Response							
EnerNOC, Inc.	O	A	O	F	O	F	A
Vermont Energy Investment Corp.	A	F	A	O	O	F	F
Small LR Group Member	F	F	A	O	A	F	F
LR Provisional Group Member	F	F	F	F	O	F	A
IN FAVOR (F)	1	6	1	3	1	6	5
OPPOSED (O)	2	0	2	4	5	0	0
TOTAL VOTES	3	6	3	7	6	6	5
ABSTENTIONS (A)	4	1	4	0	1	1	2

ATTACHMENT 2

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

SUPPLIER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
BP Energy Co.	A	A	A	F	A	A	A
Brookfield Energy Marketing /CSC	S	S	S	S	S	S	S
Brookfield Energy Marketing	F	F	F	F	A	A	A
Cross-Sound Cable	A	F	F	F	O	A	A
Calpine Energy Services	O	O	F	F	O	--	O
Competitive Energy Services, LLC	A	F	F	F	O	F	F
Consolidated Edison Energy, Inc.	A	A	F	F	O	A	O
Dynegy Marketing and Trade, LLC	O	A	F	F	O	A	O
Energy America, LLC	A	A	A	A	A	A	A
Exelon Generation Company	O	F	A	F	O	F	O
Galt Power, Inc.	A	A	A	A	A	A	A
Granite Ridge/Merrill Lynch Commodities	O	A	F	F	O	A	O
H.Q. Energy Services (U.S.) Inc.	O	F	O	F	F	F	F
Hess	A	A	A	A	A	A	A
Integrys Energy Services, Inc.	A	A	A	A	A	A	A
Kimberly-Clark Corporation	A	A	A	A	O	A	A
Linde Energy Services, Inc.	A	A	A	A	O	A	A
LIPA	A	F	F	A	O	A	A
PPL EnergyPlus, LLC	O	A	A	F	O	A	A
PSEG Energy Resources & Trade LLC	O	F	F	F	O	F	O
Vitol Inc.	A	A	F	F	O	A	A
IN FAVOR (F)	0.7	6	9	12	1	4	2
OPPOSED (O)	7	1	1	0	12.3	0	6
TOTAL VOTES	7.7	7	10	12	13.3	4	8
ABSTENTIONS (A)	11.3	12	9	7	5.7	14	11

PUBLICLY OWNED ENTITY

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Ashburnham Municipal Light Plant	F	O	A	O	O	O	O
Boylston Municipal Light Dept.	F	O	A	O	O	O	O
Braintree Electric Light Department	F	O	F	O	O	A	O
Chicopee Municipal Lighting Plant	F	O	A	O	O	O	O
Concord Municipal Light Plant	F	O	F	O	O	A	O
CT Municipal Electric Energy Coop.	F	O	F	O	O	O	O
Groton Electric Light Dept.,	F	O	A	O	O	O	O
Hingham Municipal Lighting Plant	F	O	F	O	O	A	O
Holden Municipal Light Dept.	F	O	A	O	O	O	O
Holyoke Gas & Electric Dept.	F	O	A	O	O	O	O
Hudson Light and Power Dept.	F	O	A	O	O	O	O
Hull Municipal Lighting Plant	F	O	A	O	O	O	O
Ipswich Municipal Light Dept.	F	O	A	O	O	O	O
Littleton (MA) Electric Light Dept.	F	O	F	O	O	A	O
Littleton (NH) Water & Light Dept.	F	A	F	O	O	--	--
Mansfield Municipal Electric Dept.	F	O	A	O	O	O	O
Marblehead Municipal Light Dept.	F	O	A	O	O	O	O
Mass. Municipal Wholesale Electric Co.	F	O	A	O	O	O	O
Middleborough Gas and Electric	F	O	A	O	O	O	O
Middleton Municipal Electric Dept.	F	O	A	O	O	O	O
New Hampshire Electric Coop.	F	O	F	O	O	A	O
Paxton Municipal Light Dept.	F	O	A	O	O	O	O
Peabody Municipal Light Plant	F	O	A	O	O	O	O
Princeton Municipal Light Dept.	F	O	A	O	O	O	O
Rowley Municipal Lighting Plant	F	O	A	O	O	O	O
Russell Municipal Light Department	F	O	A	O	O	O	O
Shrewsbury's Electric & Cable Operations	F	O	A	O	O	O	O
South Hadley Electric Light Dept.	F	O	A	O	O	O	O
Sterling Municipal Electric Light	F	O	A	O	O	O	O
Taunton Municipal Lighting Plant	F	O	F	O	O	A	O
Templeton Municipal Lighting Plant	F	O	A	O	O	O	O
Vermont Electric Cooperative	F	O	F	A	O	A	A
VT Public. Power Supply Authority	F	O	F	A	O	A	A
Wakefield Municipal Gas and Light	F	O	A	O	O	O	O
Wallingford, Town of	F	O	F	O	O	A	O
Wellesley Municipal Light Plant	F	O	F	O	O	A	O
W. Boylston Municipal Lighting Plant	F	O	A	O	O	O	O
Westfield Gas & Electric Light Dept.	F	O	A	O	O	O	O
OIN FAVOR (F)	38	0	12	0	0	0	0
OPPOSED (O)	0	36	0	37	38	26	35
TOTAL VOTES	38	36	12	37	38	26	35
ABSTENTIONS (A)	0	2	26	1	0	10	1

ATTACHMENT 2

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

END USER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Cianbro Companies	A	F	F	A	O	F	A
Connecticut Office of Consumer Counsel	F	A	F	O	O	F	F
Conservation Law Foundation	O	F	O	O	F	F	F
Corinth Wood Pellets, LLC	A	F	F	A	O	F	A
Dragon Products Company	A	F	F	A	O	F	A
Elektrisola, Inc.	A	F	F	A	O	F	A
Environment Northeast	F	F	A	A	O	A	--
Fairchild Semiconductor Corporation	A	F	F	A	O	F	A
Food City, Inc.	A	F	F	A	O	F	A
Hardwood Products Company	A	F	F	A	O	F	A
Harvard Dedicated Energy Limited	A	F	F	O	O	A	A
High Liner Foods (USA) Inc.	F	F	F	A	O	F	A
Industrial Energy Consumer Group	F	F	F	F	O	F	A
LaBree’s Inc.	A	F	F	A	O	F	A
Maine Public Advocate Office	A	F	F	A	O	F	F
Maine Skiing, Inc.	F	F	F	F	O	F	A
Marden’s Inc.	A	F	F	A	O	F	A
Mass. Attorney General's Office	O	F	F	O	O	F	F
MoArk, LLC	A	F	F	A	O	F	A
NH Office of Consumer Advocate	A	F	A	O	O	F	F
PalletOne of Maine	A	F	F	A	O	F	A
PowerOptions, Inc.	A	F	F	O	O	F	F
Praxair, Inc.	A	A	A	A	O	A	A
St. Anselm College	A	F	F	A	O	F	A
Shipyard Brewing Co., LLC	A	F	F	A	O	F	A
The Energy Consortium	A	F	F	O	O	A	A
Union of Concerned Scientists	O	F	O	O	A	F	F
Utility Services Inc.	A	A	A	O	A	A	A
Westerly Hospital, The	A	F	F	A	O	F	A
Z-TECH, LLC	A	F	F	A	O	F	A
IN FAVOR (F)	5	27	24	2	1	25	7
OPPOSED (O)	3	--	2	9	27	0	0
TOTAL VOTES	8	27	26	11	28	25	7
ABSTENTIONS (A)	22	3	4	19	2	5	22

ATTACHMENT 3

ESTIMATED 2014 NEPOOL BUDGET COMPARED TO
2013 NEPOOL BUDGET AND 2013 PROJECTED ACTUAL EXPENSES

Line Items	**2014 Proposed Budget**	**2013 Approved Budget**	**2013 Current Forecast**
NEPOOL Counsel Fees (1)	$3,600,000	$3,600,000	$3,600,000
NEPOOL Counsel Disbursements (1)	$ 55,000	$ 55,000	$ 55,000
Independent Financial Advisor Fees and Disbursements (2)	$ 50,000	$ 60,000	$ 50,000
Committee Meeting Expenses	$ 650,000	$ 650,000	$ 647,000
Review Board Compensation (4)	$ 108,000	$ 112,000	$ 112,000
Review Board Administrative and Support Expense	$ 30,000	$ 30,000	$ 30,000
CFTC Counsel (5)	$ 0	$ 10,000	$ 40,000 (6)
Generation Information System (3)	$1,065,000	$1,065,000	$1,046,000
Credit Insurance Premium (3)	$ 450,000	$ 425,000	$ 425,000
NEPOOL Audit Management Subcommittee (“NAMS”) Consultant (7)	$ -	$ -	$ -
SUBTOTAL EXPENSES	$6,008,000	$6,007,000	$6,005,000
Revenue			
NEPOOL Membership Fees (3) (8)	($1,800,000)	($1,750,000)	($1,855,000)
Generation Information System (3) (9)	($1,065,000)	($1,065,000)	($1,046,000)
Credit Insurance Premium (3) (10)	($ 450,000)	($ 425,000)	($ 425,000)
TOTAL REVENUE	($3,315,000)	($3,240,000)	($3,326,000)
TOTAL NEPOOL EXPENSES	**$2,693,000**	**$2,767,000**	**$2,679,000**

Notes

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

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

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

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

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

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

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

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

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

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