FINAL

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, February 1, 2013 at the Sheraton Framingham Hotel & Conference Center, 1657 Worcester Road, Framingham, 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.

APPROVAL OF JANUARY 4, 2013 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the January 4, 2013 meeting, as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes for the January 4 meeting were unanimously approved.

CONSENT AGENDA

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

ORDER 755 REVISED COMPLIANCE PROPOSAL (FREQUENCY REGULATION COMPENSATION)

Mr. Thomas W. Kaslow, Vice-Chairman of the Markets Committee, referred the Committee to the materials circulated in advance of the meeting regarding the ISO's revised compliance proposal in response to Order 755 and the FERC's November 8, 2012 order in Docket No. ER12-1643 on the region's initial Order 755 compliance filing. He reported that the

Markets Committee considered and recommended Participants Committee support for the changes at its January 29, 2013 meeting.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1, Appendix F to Market Rule 1 and the Tariff's centralized Definitions, and the deletion of Appendix J to Market Rule 1, proposed in response to FERC's November 8, 2012 order in Docket No. ER12-1643, as recommended by the Markets Committee at it January 29, 2013 meeting and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

The representative of the Massachusetts Attorney General's Office (MA AG) commented that the MA AG would abstain on the motion because of concerns over the cost-effectiveness of the FERC required changes to the reserve markets. He noted that the changes reportedly required a $3.5 million expenditure for a $14 million market. That representative noted, however, that the MA AG believed the changes were in compliance with the FERC Order. The representative stated the MA AG would not file a formal protest with the FERC.

Without further discussion, the motion was then voted and unanimously approved, with abstentions noted by representatives of Energy America, Hess, Integrys, MA AG, and the Small Renewable Generation Group Member.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the January 4, 2013 meeting, which were circulated in advance of the meeting. There were no questions on the Board meeting summaries.

He then referred the Committee to the 2013 Regional Electricity Outlook, as circulated in advance of the meeting, which he characterized as a plain English version of the issues/discussions of the ISO's initiatives over the past two years. He explained that the report was intended for a broader audience than the Participants and representatives of the New England state regulatory community that were intimately involved in those discussions and welcomed feedback on the document.

Mr. van Welie then previewed the planned presentation by Mr. Paul Hibbard, of the Analysis Group, regarding preliminary work in support of the a planned impact analysis for proposals to address the risks associated with New England's increased reliance on natural gas. He stated that, following the March 1 Participants Committee, Dr. Robert Ethier would discuss the ISO's plans for that impact analysis in order to receive feedback on those plans.

INFORMATION RELATED TO POTENTIAL FUTURE IMPACT ANALYSIS TO ADDRESS RESOURCE PERFORMANCE

Mr. Hibbard referred the Committee to the two memoranda, circulated in advance of the meeting, that reviewed information related to how various resource performance issues, including those arising from increased reliance on natural gas, were impacting, and may impact, future costs to the region. He emphasized that the ISO was in the very early development stage of producing a report on the impacts of various proposals and saw the memoranda as a good base of relevant information and data in a consistent format with which to compare those various options.

He explained that the first memorandum addressed the challenge of defining economic benefits associated with reliability improvements. He reviewed the following two key factors in assessing potential impacts:

(1) the degree of vulnerability to the region associated with natural gas infrastructure conditions; and

(2) the impact of the incidence and magnitude of outages, measured both directly (through compliance with prescriptive reliability standards) and indirectly (by measuring the value of loss of load (VOLL), derived principally from damages from actual loss of load events and estimates of losses from postulated outages within identified regions).

Mr. Hibbard provided an overview of the significant power system and market benefits associated with implementing changes to address gas dependence risks by:

- Increasing the visibility of electric and natural gas system conditions to control room operators;
- Improving the efficiency of market and system operations;
- Reducing generating asset out-of-merit commitment and dispatch for energy and reserves;
- Increasing reliability through reduced loss-of-load probability (LOLP);
- reducing the likelihood of the substantial public safety and economic impacts that flow from power outages; and
- providing financial signals for investment that encourage development of resources that will allow ISO to better manage system operations in the face of fuel uncertainties and greater integration of intermittent, renewable resources.

Mr. Hibbard then reviewed the second memorandum addressing the range of costs associated with potential market responses to address the risks associated with New England's increased reliance on natural gas. He noted that this memorandum primarily was a summary of various studies, reports, and analyses conducted by third parties related to natural gas and dual-fuel infrastructure options that could emerge from Market Rule changes. He stated that the Market Rule changes contemplated to address increased reliance on natural gas were expected to provide substantial reliability and efficiency benefits.

He then identified the following potential infrastructure changes and elements of costs:

- Increases in dual-fuel capability or operations;
- New natural gas interstate pipeline capacity;
- New in-region LNG storage; and
- Storage/transportation arrangements tied to existing LNG facilities.

He added that the effectiveness and viability of these potential changes to infrastructure, from reliability and market perspectives, depended on (1) relative costs (fixed and variable), (2) feasibility and timeline for development, and (3) operational characteristics.

Following Mr. Hibbard's presentation, the Committee provided feedback on the memoranda. A number of members questioned the reported costs of the various infrastructure options, suggesting much higher and different costs than identified. There was some discussion of the underlying basis for those cost estimates, with much of that discussion focusing on the throughput upon which $/kWh calculations were based. Mr. Hibbard responded to these comments, indicating also that there could be much difference of opinion concerning the opportunity and carrying costs for LNG fuel assumed in any cost calculation, particularly given the international nature of the LNG market.

There also was discussion of whether cost impact calculations should be more closely referenced to peak gas prices since that was when gas was likely most in demand. They inquired as to the Analysis Group's opinion as to the magnitude and duration of the high spreads between natural gas costs in US versus Europe. Mr. Hibbard responded that the Analysis Group was still reviewing and analyzing information related to that issue.

Following further input and suggestions, Mr. Van Welie explained that questions as to how ISO planned to use the Analysis Group memoranda in its planned impact analysis would be the subject of Dr. Ethier's discussion at the announced meeting on March 1, following the Participants Committee meeting. In response to questions, he indicated that he expected there would be two parallel discussions taking place. One discussion, which has already been initiated, is focused on how to get the right performance incentives into the market, in order to provide greater assurance that generators will produce electrical energy to meet load when needed. The second discussion, which is being initiated with the benefit of the Analysis Group reports, is to review how to assess the impact of the various options for providing such incentives.

Mr. Van Welie went on to report that state regulators were considering together what the region could do to increase pipeline infrastructure into New England, considering both the growing demand for heating by residential and commercial customers and the potential for additional incremental generation capacity. He reminded the Committee that the ISO is seeking Market Rule changes to provide payment for fuel services. He added that the ISO did not intend to identify or insist on an optimal fuel service for each generator, but rather expected that different generators will choose different options. He suggested the NEPOOL stakeholder process should focus on getting the market design right and then the state regulators can look at whether they want to shape or steer an investment in pipeline infrastructure into the region in parallel to those Market changes.

A member commented that, preliminarily, the FCM performance incentives mechanism being discussed would result in more revenues going to the resources providing the reliability at the expense of the resources that do not. Such a design, he opined, would be far more challenging for investment that looks to sign a 10-20 year contract to secure pipeline capacity.

Referring to the Black & Veatch Study prepared for the New England Gas-Electric Focus Group, a member requested in the ISO's later study phases that there be more analysis of the location-specific costs and benefits associated with infrastructure updates and solutions. He explained that such data and analysis would help amplify or determine value of demand response at specific locations. Mr. van Welie responded that discussion of that issue would be better saved for the planned March 1 meeting when the group could explore the scope of the planned impact study.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the February COO report, which included data only through January 27, 2013 (with the exception of LMP-related information, which was through January 29), and was circulated in advance of the meeting and posted on the ISO website. Focusing specifically on report highlights, he stated that in January: (i) natural gas prices were 65% higher and oil prices were 2.3% higher than December 2012 average values; (ii) Real-Time Hub LMPs were 100% higher than December 2012 averages; (iii) Net Commitment Period Compensation (NCPC), totaling $20.1 million, was $11.9 million higher than December 2012 NCPC; (iv) first contingency payments, totaling $17.8 million, were $12.6 million higher than December's first contingency payments; (v) second contingency payments totaled $95,000, which was lower than the $136,000 in December; and (vi) voltage support payments continued to be high and totaled $1.9 million, down $1.1 million from December. He reported that, based on a 50/50 and 90/10 load forecast, the lowest Winter Operable Capacity Margin was projected for the week beginning February 9, with the lowest 50/50 and 90/10 Spring Operable Capacity Margin projected for the week beginning May 11.

Dr. Chadalavada reported that the seventh Forward Capacity Auction (FCA7), for the 2016/2017 Commitment Period, was scheduled for the week of February 4, and would include the modeling of four zones. The ISO expected to make the FCA7 results filing with the FERC by the end of February. He reported that the 2013 Economic Study Requests are due to be submitted by April 1.

Dr. Chadalavada then provided a summary of the winter operations over the prior ten days. He said the week ending January 26 had the five coldest days consecutively since the week of January 19, 2009, but had avoided the deep freeze or Cold Snap experienced in New England in prior years, and given day-time temperatures, wind chills, and load, was relatively moderate when compared to 2004. He reported that the overall peak load was 20,822 MW, which was less than the forecasted 50/50 peak of 21,392 MW. He stated there were two factors that helped New England reliability and operations over those ten days: (1) significant natural gas flow from the north on the Maritimes and Northeast and Portland Natural Transmission Pipelines; and (2) oil unit operations. He noted the high gas prices resulted in oil units being in merit for several days, with gas units providing supplemental commitments. He said that Hydro

Quebec experienced an all-time peak load, which limited exports to New England. He stated that, even with the loads under the 50/50 peak of 21,392 MW and the high utilization of the gas pipelines from the West and North, the ISO still had difficulty ensuring capacity to meet load and operating reserve requirements.

Dr. Chadalavada concluded his presentation, reporting that the ISO implemented OP4 on January 28 when capacity deficiency was driven by unit outages and loads higher than forecasted. He said that initial indications showed that Demand Response performed well and more details on the performance would be available in the next several days.

Members then commented and asked clarifying questions on the COO report. In response to a member's question about how close the region came to being unable to meet the full demand, Dr. Chadalavada stated the 90/10 forecast would produce a 22,300 MW load, about 1,600 MW higher than load actually experienced. He said that the ISO was performing simulations to understand better the region's ability to meet demand as demand approaches the forecasted peak, including under scenarios of reduced availability of gas from the north and where neighboring Control Areas are also experiencing similar cold conditions.

A member suggested revisiting whether ICR calculations were still proper, in light of the many fundamental changes in the markets. Dr. Chadalavada agreed that the ISO needed to relook at the ICR assumptions related to forced outages, reserves, and tie benefits, noting such a review would be a long process.

A member expressed concern with Dr. Chadalavada's suggestion that, because of increased dispatch of oil units in the Day-Ahead Energy Market, gas units would be scheduled more often in the Reserve Adequacy Assessment (RAA) process. He asked what could be done in the Winter Periods to encourage greater scheduling of gas generation in the Day-Ahead Energy Market and suggested looking at the load-side to contribute to the solution. Dr. Chadalavada referred to an exhibit in the report that showed that, as temperatures dropped, the percent of load that cleared Day-Ahead decreased, forcing the ISO to increase supplemental commitments. To address this, and as part of the 2013 Work Plan, he stated the ISO would pursue Ancillary Service Markets improvements, and planned to file such improvements with the FERC in the 2nd quarter of 2013 for potential implementation ahead of the next Winter Period.

A member expressed concern with the inability to predict events that magnify demands on gas generators that are first identified in the RAA and how those events are treated under existing procedures. He suggested that a potential solution may be to increase the quantity of reserves. Dr. Chadalavada responded that concerns like this were to be discussed over the next ten months, with focus on clarifying the obligations of the capacity resources and the assumptions that do go into the ICR. He said that the ISO intended to position the System for the next-day with the key concern for reliability and a slight bias towards being conservative.

In response to questions and comments regarding Demand Resources (DR), Dr. Chadalavada reported that DR could currently bid in a price at which it was willing to be interrupted, and could be called on in limited circumstances. He explained that, in 2016, the plan was to have full DR participation in the energy market.

Dr. Chadalavada noted in response to a member’s question that the ISO was targeting on tight days to come into the morning ramp with 1,500 MW in supplemental reserves and about 800 MW of supplemental reserves for the afternoon peak. To do this, the ISO called on some, but not all, long lead-time units. The ISO tried also to carefully balance the benefit of supplemental reserves against the depletion of fuel inventory.

Referring to a slide reflecting posturing the system, a member asked whether uplift payments were reflected in the first contingency category and whether costs associated with supplemental reserve posturing could be broken out in a future report. Dr. Chadalavada confirmed that related uplift payments were included in first contingency and agreed to provide a breakdown as requested. In follow up to a question of whether there were any curtailments due to lack of gas, and if there were any resources that violated their Tariff obligations, Dr. Chadalavada stated that, since the discussion around obligations in November, the ISO had seen gas resources working much harder to procure the fuel needed for their dispatch. He explained that some of that performance may have been related to increasing IMM flexibility in the re-offers that it would allow, recognizing that such re-offers could reflect either a switch to oil or be based on index prices for next-day gas.

In response to members' comments regarding ICR calculations and Capacity Supply Obligations following each of the reconfiguration auctions, Dr. Chadalavada stated the ISO needed to perform additional analysis with the benefit of import flow data actually experienced on peak days and report back on, and undertake to respond, as appropriate to, that analysis. In order to better understand ISO operations, and impacts on market timing, a member requested that the ISO provide information from the recent period on the commitments that it made in the RAA process and the amount of manual commitments made prior to RAA deadlines. Noting potential limitations, the ISO committed to provide what information it reasonably could.

Dr. Chadalavada responded to an open question from the prior month's report with regard to Minimum Generation Warnings and Emergencies (Min Gen Events). He explained that ISO analysis was ongoing as to whether the increased Min Gen Events may be a new normal or instead limited to winter 2012/13 because of unit posturing issues. He predicted that Min Gen Events may well be the new normal during Winter Periods and when Day-Ahead loads are less than predicted, given increasing supplemental commitments.

2013 BUSINESS PRIORITIES / WORK PLAN

Dr. Chadalavada referred the Committee to the presentation of the 2013 Work Plan (Work Plan), as circulated in advance of the meeting and posted on the ISO website. He indicated that the discussion of the Work Plan was a continuation from the January 4 meeting and noted that the presentation had been updated in response to feedback received. He identified specifically that the updated presentation identified the source driving each activity's inclusion in the Work Plan and a subjective assessment as to the relative impact of each activity on markets and reliability.

Capital Project Priorities

Dr. Chadalavada highlighted and provided an overview of the following Capital Project priorities:

- Backup Control Center – explaining NERC/NPCC standards requiring all back up systems (markets, energy management, reliability functions) to be activated within two hours and operated for an indefinite period of time; activation planned for Q2 2014;
- Day-Ahead Market Move – explaining that either the ISO or NEPOOL Proposal included in the jump ball filing to be filed shortly could be implemented; June 2013 implementation planned given ripple effect of those Market Rules;
- Intra-Day Offers – explaining its importance to gas/electric coordination issues; FERC filing in Q2 2013, with implementation by October 1, 2014;
- Intra-Day Reserves – changes to Locational Forward Reserve Market (LFRM) (new Reserve Constraint Penalty Factor (RCPF) trigger, improved incentives in LFRM); implementation planned for the 2014 Winter auction; and more extensive changes (new reserve product) in 2014;
- Generation Control Application – explaining that this change was to allow the ISO to look ahead 2-4 hours (rather than 15 minutes) when it dispatches; implementation in Q2 2014; and
- Coordinated Transaction Scheduling (CTS) – explaining challenges in harmonizing and finalizing operational protocols (particularly in cases of reserve shortages in both areas); implementation as early as Q4 2014, but more likely during 2015.

Members then commented and asked clarifying questions concerning the Capital Project priorities. Addressing potential delays in CTS implementation, one member expressed his disappointment in the delays and he and others requested that NEPOOL be involved in the ISO/NYISO CTS implementation process. In response, Dr. Chadalavada reported that the ISO planned to involve stakeholders throughout the implementation process. Another member asked whether additional improvements to the reserve bias were in the timeline and linked to the twohour look ahead. Dr. Chadalavada responded that these improvements were part of the Intra-Day Reserves project and were scheduled for implementation in the 2013 August auction.

Dr. Chadalavada concluded his presentation by referring the Committee to new additional slides (pages 73-82). He explained that, based on feedback received from members and state regulators on the initial draft Work Plan, the ISO had added the slides to include a description of the key driver for each of the ISO activities (e.g., regulatory order or compliance requirement, operations improvement, strategic planning initiative, etc.), a subjective ranking of the reliability and market efficiency impacts, and projected implementation costs for the capital project activities. Members and guests were again provided the opportunity to comment or ask follow up questions, with specific inquiry as to whether state regulators present had questions or follow up given their earlier expression of interest in this information. There were no questions or comments. Dr. Chadalavada urged anyone who wished to discuss this information to contact the ISO.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report that had been circulated in advance of the meeting, noting again the high level of activity. He reported on efforts to settle the 2013 ISO Administrative Budget proceeding. He noted progress achieved on a number of issues that had been addressed through Forward Capacity Auction (FCA)-related proceedings. He also noted the summaries of the pleadings submitted in the FCA8 Changes and Order 1000 Compliance proceedings circulated to supplement the Report summaries. Members were also advised of recent orders that would require compliance filings, one in the Information Policy Pipeline Information-Sharing Changes proceeding (ER13-356), which would be due prior to the next Participants Committee meeting, and the other related to the FERC’s order conditionally accepting the FCM conforming changes reflecting the full integration of price-responsive demand (ER12-1627).

COMMITTEE REPORTS

Mr. Joel Gordon, Chairman of the Budget & Finance Subcommittee, announced that, on a going forward basis, all Participants Committee members and alternates, in addition to those who specifically identified an interest in participating in the Subcommittee's meetings, would receive Subcommittee meeting notices in an effort to highlight the forum for, and discussions addressing, budget-related issues.

On behalf of Mr. Fernando DaSilva, Chairman of the NEPOOL Audit Management Subcommittee (NAMS), Mr. Doot reported that NAMS had received two reports/updates from the ISO's Internal Audit Division providing results of its 2012 audits and plans for its 2013/2014 audits. Mr. Doot reported that, if it was interested, the Committee was again entitled to request an audit of the ISO's performance under the three-year schedule provided for in the Participants Agreement and would look to NAMS for any such recommendation. He encouraged all those interested to let Mr. DaSilva or NEPOOL Counsel know so they would be sure to receive any NAMS-related notices or materials. Mr. DaSilva indicated that a summary of the recent reports and notice of the next NAMS meeting would be circulated to the Committee.

OTHER BUSINESS

Mr. Doot referred the Committee to the NEPOOL calendar for February and March, highlighting upcoming meetings and events. He reminded the Committee that the next regularly-scheduled meeting of the Participants Committee would be March 1 at the Hilton Logan Airport Hotel in Boston, MA, to be followed by a discussion of the ISO's planned impact analysis of proposals to address the risks from New England's increasing reliance on natural gas. Mr. Doot highlighted the scheduled technical conference on gas-electric coordination to be held at the

FERC on February 13, some of which related to issues being addressed specifically in New England and that may have contributed to the guidance provided in the recent Information Policy Pipeline Information-Sharing Changes proceeding. He encouraged all those interested to participate in that technical conference, as well as in the next meeting of the New England Gas-Electric Focus Group scheduled for February 26. Looking to March, Mr. Doot highlighted the March 4 settlement conference in the 2013 ISO Budget proceeding, and the Consumer Liaison Group meeting scheduled for March 13.

There being no further business, the meeting adjourned at 12:30 p.m.

Respectfully submitted,

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David T. Doot, Secretary

**MEMBERS AND ALTERNATES PARTICIPATING IN
FEBRUARY 1, 2013 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	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing Inc. / CSC	Supplier	Nicolas Bossé (tel)	Jose Rotger	
Calpine Energy Services, LP	Supplier	John Flumerfelt		
Central Maine Power Company	Transmission	Eric Stinneford (tel)		
Cianbro Companies	End User	Gus Fromuth		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Comverge	AR	John Driscoll (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			Paul Peterson
Conservation Law Foundation (CLF)	End User		N. Jonathan Peress	
Conservation Services Group (CSG)	AR	Doug Hurley (tel)		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Corinth Wood Pellets LLC	End User	Gus Fromuth		
CP Energy Marketing (US) Inc. (Capital Power)	Supplier	Michelle Gardner		
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart (tel)		
Dragon Products Company LLC	End User	Gus Fromuth		
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User	Gus Fromuth		
Energy America, LLC	Supplier	Ron Carrier		Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, Inc.	Generation	Marc Potkin (tel)		
EP Energy Massachusetts, LLC	Generation	M.Q. Riding (tel)		William Fowler
EquiPower Resources Management, LLC	Generation		William Fowler	
Exelon New England Holdings / Constellation	Supplier	Steve Kirk	William Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
First Wind Energy Marketing, Inc.	AR	Carter Scott (tel)		Francis Pullaro (tel))
Food City, Inc.	End User	Gus Fromuth		
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		
Generation Group Member	Generation		Abby Krich	
Granite Ridge/Merrill Lynch	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier		Robert Stein	
Hardwood Products Company	End User		Gus Fromuth	
Harvard Dedicated Energy Limited	End User			Roger Borghesani
Hess Corporation	Supplier			Nancy Chafetz
Holden Municipal Light Department	Publicly Owned		Gary Will	
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Kimberly-Clark Corporation	Supplier			Vicki Karandrikas (tel)
Linde Energy Services	Supplier			Vicki Karandrikas (tel)
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny (tel)	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	

ATTACHMENT 1

**MEMBERS AND ALTERNATES PARTICIPATING IN
FEBRUARY 1, 2013 PARTICIPANTS COMMITTEE MEETING**

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Marden's Inc.	End User	Gus Fromuth		
Mass. Attorney General's Office	End User	Fred Plett	Patrick Tarmey	
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, Inc.	End User	Gus Fromuth		
New England Power Company (National Grid)	Transmission	Timothy Brennan		
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Fernandno DaSilva		
NU / NSTAR	Transmission	James Daly	Calvin Bowie	Joe Staszowski, Bob Clarke
PalletOne of Maine	End User	Gus Fromuth		
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cindy Arcate		
PPL EnergyPlus (PPL)	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Vicki Karandrikas (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member – Load Response Sub-Sector	AR	Brad Swalwell (tel)		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
RJF-Morin Brick LLC	End User	Gus Fromuth		
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley (tel)		
Small Load Response Group Member	AR	Doug Hurley (tel)		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
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	
Texas Retail, LLC	Supplier	Chris Hendrix (tel)		
The Energy Consortium	End User	Roger Borgesani		
TransCanada Power Marketing Ltd.	Generation		Mike Hachey	
Union of Concerned Scientists (UCS)	End User	Paul Peterson		
United Illuminating Company, The (UI)	Transmission		Alan Trotta	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny (tel)		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori		Mark Sciarrotta
Vermont Energy Investment Corporation	AR		Doug Hurley (tel)	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		
Vitol Inc.	Supplier	Joseph Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital	End User		Gus Fromuth	
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
ZTECH, LLC	End User		Gus Fromuth	