FINAL

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, September 9, 2016, at the Radisson Manchester Hotel, Manchester, New Hampshire, 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 who participated in the meeting.

Mr. Joel Gordon, Chairman, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF AUGUST 5, 2016 MINUTES

Mr. Doot referred the Committee to the preliminary minutes of the August 5, 2016 meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes were unanimously approved without discussion or change.

CONSENT AGENDA

Mr. Gordon 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 discussion or comment.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the September COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing on highlights, he reported for August that: (i) Energy Market value was $508 million, up $64 million from July 2016 and up $83 million from August 2015; (ii) average natural gas prices were 12.8% higher than July 2016 average values; (iii) Real-Time Hub LMPs on average were 37% higher than July 2016 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 99.3%, up from 97.9% in July; (v) daily Net Commitment Period Compensation (NCPC) totaled $6.5 million, up

$2.6 million from July 2016 and up $785,000 from August 2015; (vi) first contingency payments, totaling $5.4 million, were $3.0 million higher than July's; (vii) second contingency payments, totaling $1.0 million, were down $465,000 from July; and (viii) NCPC payments were 1.3% of the total Energy Market value. He reported the second contingency payments were almost all in Northeastern Massachusetts/Boston (NEMA), a function of the loads during six days in August. He noted that Greater Boston transmission upgrades were scheduled to be in service in the next two months and, until then, there may be sporadic need for commitment to meet second contingency requirements.

Dr. Chadalavada reported that the ISO presented at the August 17 Planning Advisory Committee (PAC) meeting draft results of its analysis of five scenarios requested in the 2016 Economic Study (the NEPOOL Scenario Analysis) process. He said that further discussions were planned for the September 21 PAC meeting. He expressed the ISO's hope that the results might help inform the process underway to explore integrating markets and public policy (IMAPP).

Reviewing additional highlights, he reported that: the Keene Road Market Efficiency Transmission Upgrade Needs Assessment scope of work would be discussed at the September 21 PAC meeting; qualification of new resources for participation in the eleventh Forward Capacity Auction (FCA11) would be completed by the end of September; the ISO would be holding an informational session in November to discuss potential capacity zones for FCA12; and the ISO expected construction and maintenance of natural gas pipelines that are relied on by generators in the region to continue through late November. In response to a question from a member, Dr. Chadalavada committed to break out in future reports the NCPC costs relating to unit posturing.

Dr. Chadalavada then reviewed an Operating Procedure No. 4 (Action during a Capacity Deficiency) (OP-4) event that occurred on August 11 to manage a shortage of Thirty-Minute

Operating Reserve (TMOR). He reported that: the ISO entered M/LCC 2 (Abnormal Conditions Alert) due to forced generator outages of approximately 1,425 MW; the ISO projected in the morning that it would have a 324 MW Operating Reserve surplus (based on a forecast peak load of 25,100 MW); the ISO experienced peak hour forced outages and reductions of 4,294 MW compared to the 2,266 MW anticipated that morning; imports during the peak totaled 3,462 MW versus 2,995 MW anticipated that morning; and the ISO dispatched Real-Time Demand Resources (RTDR) except in Maine, which was experiencing a transmission export constraint. He then reviewed slides showing the load forecast versus actual load, Real-Time pricing and reserves, and initial RTDR performance.

A question was raised as to why it took almost two hours after the forced outage of a large generator for the ISO to declare OP-4 Action 1. Dr. Chadalavada explained that the loss of the single unit itself during the morning did not trigger OP-4, as there was sufficient TMOR, ability to ramp the capability of the system, and imports and surplus Operating Reserve carried into the day. He said that OP-4 became necessary as the region continued to lose other units and had a need to reduce the output of other units, with the cumulative effect of the outages and reductions, as load grew through the day, triggering OP-4 at 13:50 and not at 9:58. He reported that the FCM Shortage Event penalties on August 11 totaled $7.3 million and the incremental FCM Peak Energy Rent (PER) deductions totaled $101 million ($8.4 million per month). He also informed the Committee that any associated PER charges would begin to show up in the September 2016 FCM bill that would be issued to affected Participants in October 2017 and assessed over a 12-month (September 2016 to August 2017) period.

In response to questions, Dr. Chadalavada stated that the August 11 circumstances would definitely have been classified as a Shortage Event under the pay-for-performance (PFP) mechanism to be implemented. He explained that the ISO might be able to simulate the results of the August 11 event under PFP, but such a simulation would be time consuming and only about 80% accurate. Nevertheless, he committed the ISO to undertake that simulation effort and provide results to the Participants that would have been impacted. He confirmed that, in the aggregate, the PER paid by generators would be nearly 10% of the capacity revenues for the entire year, but reminded members that the PER mechanism would cease on June 1, 2019.

Dr. Chadalavada concluded his presentation summarizing charts and responding to questions and comments concerning fuel diversity, estimated solar production and forecast, and total aggregate interchange with neighbors on August 11.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the written summaries that were circulated and posted in advance of the meeting, of the ISO Board and Board Committee meetings that had occurred since the August 5 Participants Committee meeting. There were no questions or comments on the summaries.

He reported on his observations from the CIGRE[1] session he attended in Paris, France, noting that countries around the world were all working on addressing the challenges of integrating large quantities of renewable energy onto their power systems and addressing the impact of those renewables on operations and markets. He observed that Europe was 5-10 years ahead of New England from both an operational point-of-view and a planning perspective in terms of operating a system with a high penetration of renewables, but that New England was 5-10 years ahead of Europe from a market design perspective, i.e. achieving reliability through markets. He noted that New England's challenge was how to maintain what had been built while finding a way to integrate public policy into the region's market design. He concluded that these

[1] CIGRE is an international non-profit Council on Large Electric Systems, with a mission of bringing together experts from around the world to explore ways to improve current and future electric power systems.

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observations highlighted the importance of the IMAPP efforts, the ongoing economic studies, and the plans for analyzing operability in the future. He stated that he was cautiously optimistic that current efforts would produce productive results in the coming months and years.

Mr. Gordon asked Mr. van Welie to comment on his recent quotes in a trade magazine to the effect that he believed New England's markets were in their most vulnerable position in relation to integrating public policy objectives into the market design and preserving markets. Mr. van Welie responded that his quote related to his assessment of the ability of the markets to assure resource adequacy, which depends on investors' confidence that they can invest in resources and have the opportunity in the markets to recover their investments over time. He stated that, given the alignment of the region's states and stakeholders, New England was in a fairly unique position, and it was in New England's best interest to innovate and to find a solution through the IMAPP process.

Noting the impact of renewable resources on operations around the world, one representative reported there were days last year in Denmark where energy produced by wind exceeded demand by 115% to 140%. Similarly, he stated that, earlier in 2016, load obligations in Portugal had been met for 110 consecutive hours relying solely on solar, wind and hydro resources; Costa Rica operated solely on renewable power for 76 days. Mr. van Welie responded that he had talked with Denmark system operators and learned that they can rely on renewables as they do because they balance their system with Norway's hydro energy, which is backed up by a cost-of-service gas fleet to balance the combined systems. He noted further that, in all of the systems cited, there remains a fleet of resources on standby to meet load when renewable energy is not being produced. New England, he stated, needs to find a way to ensure a similarly reliable solution. With the States continuing to encourage more renewable energy on the system, he concluded that the region's challenge was to work to ensure that the region, through markets, can pay for the resources needed to provide the required reliability services.

2017/18 WORK PLAN

Dr. Chadalavada referred the Committee to the materials circulated in advance of the meeting concerning the 2017/18 Draft Work Plan (Work Plan). He explained that the ISO's primary emphasis for 2017/18 would be implementation activities and market design changes to support previously committed work. There were three major project implementation milestones that would occur over the subsequent 21 months: (1) sloped zonal demand curves for FCA11 (with FCA 11 to be conducted on February 6, 2017); (2) Real-Time Fast-Start Pricing, Sub-hourly Real-Time Settlement, and market enhancements for Dispatchable Asset Related Demand (DARD) Pumps in March/April 2017; and (3) full integration of Price Responsive Demand and implementation of PFP on June 1, 2018. He stated that, as a result of the IMAPP efforts, price formation efforts related to the Day-Ahead Reserve Market and multi-hour ramp pricing projects will be delayed by at least one year.

A member asked the ISO to reassess in December the ISO's resources needed for IMAPP and whether an earlier implementation of the Day-Ahead co-optimized Energy and Operating Reserve market project might be possible. In response, Dr. Chadalavada committed the ISO to revisiting proposed timelines in the Work Plan with NEPOOL and the States in December 2016. Mr. Mark Karl, Vice President, Market Development, added that assessment would be consistent with the established practice of working closely with NEPOOL and its leadership as the Work Plan evolves, inevitably, through the course of the year based on a number of variables. A member expressed support for revisiting the Work Plan and expressed disappointment with the delay in addressing price formation initiatives. Since the Day-Ahead co-optimization project and the future of the locational Forward Reserve Market (FRM) had previously been tied together by

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ISO, this member encouraged the ISO to report at year's end the ISO's plans for FRM. Dr. Chadalavada agreed, noting that both the ISO's Internal Market Monitor (IMM) and External Market Monitor (EMM) had identified concerns with the current FRM, calling into question the relevance and significance of that market. He reminded members that the ISO had planned to address this issue coincident with the implementation of the Day-Ahead co-optimization of Energy and Reserves. He said that, with the Day-Ahead Reserve Market project delayed, the ISO was considering other design adjustments to FRM to address in the interim some of the Market Monitors' concerns.

A member expressed concern with delay in the multi-hour ramping price project, and another member asked about the potential impact of any further FERC directives. Dr. Chadalavada confirmed that compliance with any FERC order or direction would necessarily take precedence and the ISO may have to re-order regional priorities and the Work Plan accordingly.

Dr. Chadalavada then reviewed two key planning and operations activities, including Order 1000 and transmission planning. Mr. Stephen Rourke, ISO Vice President, System Planning, highlighted that region's Order 1000 changes became effective in May 2015. He reported that, including the three most recent applications, 14 different transmission project sponsors had been qualified (identified on the ISO website) and would be able to respond to any requests for proposals (RFPs). The PAC had been notified of the possibility of an ISO RFP for a market efficiency transmission upgrade in Maine that might be issued before the end of 2016. He noted the active discussion regarding Order 1000 implementation, both within the region and as part of the FERC's June 27-28, 2016 technical conference on competitive transmission development process-related issues. He expected further guidance from the FERC on Order 1000 implementation issues within the next year. He also stated that, in January 2017, the ISO, working with the PAC and the States, planned to initiate the first cycle of planning for Public Policy Initiatives, an Order 1000 compliance issue.

Mr. Rourke further reported that, as national transmission planning standards had evolved, NERC Standards had increased in specificity, complexity and in the range of conditions covered. The ISO was evaluating, and would work through with the Reliability Committee, ways to streamline and make more straight forward, compliance with the region's, NPCC's and NERC's transmission planning standards.

Turning to Attachment K Economic Studies, Dr. Chadalavada indicated that the first phase of the 2016 NEPOOL scope of work would be completed in 2016 and the second phase, which would look at the operability of each scenario and an assessment of additional market outcomes, in 2017. To the extent an expansion of scope or a decision to study additional variations resulted from those efforts, there would be an opportunity to do so as part of the 2017 Attachment K Economic Study process. Mr. Gordon reminded the Committee that the 2016 Attachment K Economic Study originated from the 2016 NEPOOL business priorities initiative. He asked Participants to provide their Sector Vice-Chairs with feedback on the results of the PAC study.

Addressing questions on Distributed Generation (DG) forecasting efforts, and whether the integration of irradiance data into ISO weather forecasting was a new project, Dr. Chadalavada stated the ISO was working with its wind forecast vendor, who planned to introduce new technology to the ISO on a pilot basis to improve photovoltaic (PV) forecasts. Mr. Rourke added that the ISO was also working with VELCO and other Vermont distribution utilities to receive and analyze Real-Time solar data in order to identify areas where modeling could be enhanced.

Dr. Chadalavada reported that the FCM Capacity Zone modeling process would begin in late 2016 and that the ISO would present an overview of the existing zones, discussion of relevant constraints, and factors that could trigger the use of these zones in FCA12. ISO review of Black Start compensation mechanisms was underway and, should the ISO determine following that assessment that changes should be considered, the stakeholder process to consider changes would take place in 2017 at the earliest. He then reviewed the Wind Interconnection Group Studies, noting its two parts: (1) ISO presentation, by the end of 2016, of a transmission blueprint of grid reinforcements needed to interconnect wind either in Northern Maine or Western Maine (which would shed light on the resulting cost implications); and (2) ISO presentation of a proposal on interconnection clustering incorporating national best practices. Following this process, he stated the ISO hoped to file a set of reforms with the FERC that better inform those in the queue and increase the efficiency and effectiveness of the ISO's planning studies. Mr. José Rotger, the Transmission Committee Vice-Chair, reported that the ISO would present its conceptual proposal for the cluster study project at the September 27 Transmission Committee meeting and discussions at the Transmission Committee would continue through the end of 2016. He encouraged interested Participants to attend the September 27 meeting and to actively participate in the discussions. A Maine Public Utilities Commission representative asked the ISO, as it conducts these studies, whether it considers how the studies might be different from traditional reliability studies and, should there be resources that are not needed for reliability, whether there were steps that could be taken or assumptions that could be made in planning to facilitate the interconnection of resources. Mr. Rourke stated that Mr. Alan McBride would speak to those issues at the September 27 Transmission Committee meeting. Dr. Chadalavada added that, with regard to reliability studies, once the Greater Boston Project was in-service, the region should see a significant strengthening of the hub and increased operational flexibility, with a possible FERC filing as early as mid-2017.

Dr. Chadalavada reported that the change in 2016 to a biennial Regional System Plan (RSP) cycle meant that the next RSP would be issued in 2017. Whether any further changes to the frequency of RSP publication would be necessary or desirable would be revisited after that issuance.

Dr. Chadalavada addressed the results of the ISO forums that considered the implications of moving from a Descending Clock Auction (DCA) to a Sealed Bid Auction (SBA) design (consideration of which, Mr. Gordon reminded the Committee, was identified in 2015 as a NEPOOL priority for 2016). Based on the input received from those forums, and in light of all the other priority items facing the ISO, including potentially substantial efforts in the IMAPP process, the ISO concluded that, while it could address the narrow auction mechanic switch from DCA to SBA, it could not as part of the 2017 Work Plan address the larger and more intensive related issues of mitigation, queue reform, and the like. He stated that, based on discussions with the NEPOOL Officers, the ISO planned not to take up the limited changes to the auction mechanic until 2018 or later, to be addressed along with three other deferred projects: multi-hour ramp pricing, external transaction offer flexibility, and NCPC cost allocation projects.

Dr. Chadalavada concluded his presentation highlighting cyber security requirements, impacts, and investment. He stated that the ISO planned to invest significant capital during 2017-18 and beyond in order to bolster the sophistication and the rings of defense around its critical infrastructure, its identity management systems, and other enhancements, as the scope and complexity of cyber requirements evolved. He explained that the FERC's recent Order 829 addressing supply chain risk management would significantly impact ISO information technology efforts. In addition, ISO's Energy Management System was in need of a major upgrade, which would be a multi-year effort. Additional notice and information on those efforts would be provided when the projects are chartered, and would be included in the ISO's quarterly capital funding tariff updates with the FERC.

A member expressed appreciation to the ISO for several of the big projects to be implemented in 2017, but raised concern with the deferral of the NCPC cost allocation project, noting the IMM and EMM recommendations over the past several years that NCPC allocation be revisited, particularly for virtual transactions. He appreciated competing priorities that the ISO faced, but echoing the market monitors' views, advocated strongly in favor of moving this up the priority list. Dr. Chadalavada acknowledged the member's disappointment in the deferral, but noting prior experience with, and minimal stakeholder support for, pursuing NCPC reforms at the cost of deferring other issues, the ISO was reluctant to repeat those efforts at that point, though it would continue to monitor and assess what could reasonably be achieved.

2017 ISO AND NESCOE BUDGETS

Mr. Kenneth Dell Orto, Budget & Finance Subcommittee (Subcommittee) Chairman, referred the Committee to the materials circulated in advance of the meeting related to the proposed 2017 ISO Capital and Operating Budgets and the 2017 NESCOE Budget. He reported that preliminary ISO Budgets had been reviewed and vetted at the NECPUC Symposium, the NEPOOL Summer Meeting, the Subcommittee's August 12 meeting, and separately with state agencies. Over the course of that review, Participants had not identified any particular concerns or objections. Similarly, the 2017 NESCOE Budget had been presented to Participants at the Subcommittee's August 12 meeting without objection or concern. He explained that the Budgets were being presented at this meeting to further understanding of the Budgets and help prepare for a vote on the Budgets at the October Participants Committee meeting.

Mr. Robert Ludlow, ISO Vice President and Chief Financial & Compliance Officer, then continued the summary of the 2017 Budget review process. He reported that, pursuant to the process agreed to in settlement, State Agencies had submitted questions on the proposed ISO Budgets on August 22, and the ISO had responded on August 29. Those questions and answers had been included with the materials for the meeting. The ISO Board of Directors would review the Budgets and State Agencies comments at its September 15 meeting and ISO responses to State Agencies' comments and proposed adjustments would be provided on or about September 21. The ISO Board, with the benefit of NEPOOL's October vote and all of the other input received, would then consider and vote on the 2017 ISO Budgets after the October Participants Committee meeting, with a Tariff filing on or about October 17 to support the ISO's request for the Budgets to be effective as of January 1, 2017.

Mr. Ludlow explained that the proposed 2017 ISO Operating Budget was generally in line with the services and funding included in the preliminary budget presented to the Participants Committee in June. He highlighted key aspects of the proposed 2017 Operating Budget as outlined in the presentation circulated and posted for the meeting.

He summarized that the proposed 2017 ISO Operating Budget (excluding depreciation and the true-up for past years) was 4.1% (or $7.5 million) higher than the 2016 Operating Budget. He stated that the final 2017 Operating and Capital Budgets would reflect the results of the ongoing Work Plan and priorities discussions with stakeholders, including IMAPP initiatives. He reported that, in total, the 2016 ISO revenue requirement would be 4.2% higher than in 2016.

Mr. Ludlow identified, for 2018 and beyond, the potential for material risks and that increased resource requirements would be driven by continued cyber security threats, Order 1000 implementation, and wholesale electric market enhancements, including IMAPP. He stated that, by utilizing consultants to augment work load in 2017, the ISO would be better positioned to determine whether it needed to cost effectively add permanent headcount in 2018 or beyond.

Moving to the 2017 Capital Budget, Mr. Ludlow explained that the proposed budget, which tied back to the Work Plan discussion earlier in the meeting, was $28 million, $1 million more than the 2016 Capital Budget, but consistent with Capital Budget levels prior to that. He explained further that, at this level, the ISO’s financing structures continued to be sufficient to meet the needs of the organization.

Mr. Ludlow concluded his presentation by comparing the 2015 operating expenses, capital expenditures, and outstanding debt of the ISO to those of the other North American ISO/RTOs.

Turning to the 2017 NESCOE Budget, Mr. Gordon referred the Committee to the NESCOE materials posted in advance of the meeting. He asked whether there were any comments or questions for Ms. Heather Hunt, NESCOE Executive Director. None were raised.

Mr. Gordon reiterated that the 2017 Budgets would be voted at the October 14 Participants Committee meeting. He urged members to raise any questions or concerns in advance of those votes directly with Messrs. Dell Orto and/or Ludlow.

LITIGATION REPORT

Mr. Doot referred the Committee to the September 7 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the recent FERC order conditionally accepting the FCM Composite Offers & Price Lock Mechanisms compliance filing, but directing further Tariff changes to be submitted on or before October 31, 2016. He indicated that proposed compliance changes would be presented to the Markets Committee in time for Participants Committee action at its October 14 meeting.

Mr. Patrick Gerity, NEPOOL Counsel, highlighted the FERC order dismissing without prejudice the NextEra/PSEG natural gas pipeline-related complaint, and a related order under the Natural Gas Act rejecting Algonquin's request for a waiver that would have exempted gas-fired generators from capacity release bidding requirements but accepting Algonquin's request to exempt from bidding an electric distribution company's (EDC's) capacity release to an asset manager who is required to use the released capacity to carry out the EDC's obligations under a state-regulated electric reliability program. He reported that the emergency generator waiver, requested by the ISO following the DC Circuit's decision to overturn certain Environmental Protection Agency (EPA) rules and subsequent guidance from the EPA, was granted and would permit impacted resources to take steps to remain eligible for FCA11 and other affected Capacity Commitment Periods.

Mr. Gerity summarized the status of pending Forward Capacity Auction (FCA) proceedings as outlined in the Litigation Report.

Mr. Gerity then reported that, in response to a remand order from the DC Circuit regarding the FERC's order on the 2013/14 Winter Reliability Program, the FERC had asked the ISO for additional information, including additional information from program participants and the ISO's evaluation of that information, all of which needed to be collected and assembled for an early December filing. Mr. Doot added that the IMM had already issued requests for information that it needed to respond to the FERC's request. Mr. Doot concluded by highlighting a Massachusetts judicial decision with respect to pipelines and the authority of Massachusetts regulators to assign costs to EDCs, noting that the impacts of that decision were being reviewed and discussed with the parties involved.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler reported the next Markets Committee meeting, scheduled for September 13 (September 14 had been converted to IMAPP meeting), would include a vote on changes to natural gas index used in the calculation of the Peak Energy Rent Strike Price, the Import Capacity Resource offer threshold price, and the Forward Reserve threshold price, a first look at an ISO proposal to change the definition of "force majeure," and consideration of revisions to Cost of New Entry (CONE) and Offer Review Trigger Prices (ORTPs) for FCA12.

Reliability Committee. Mr. Donald Gates reported that the Reliability Committee would meet on September 20 and would consider ICR-related values for FCA11, presentations on two proposed plans for HVDC lines coming into Vermont, an ISO presentation on Order 1000 integration and the I.3.9 process, and an overview of the August 11 OP-4 event.

Transmission Committee. Mr. Rotger reported that the Transmission Committee was scheduled to meet on September 27, with an additional meeting scheduled for October 11. At the September 27 meeting, the Transmission Committee was to begin discussions of the cluster study, to review and possibly to act on NEPOOL comments in response to the FERC's questions on Order 1000 issues following its June 27-28 Technical Conference, to vote on continuation of the Schedule 2 Reactive Power and Voltage Support Capacity Cost (CC) Compensation Rate, and to review 2016/17 Regional Network Service (RNS) rate information. A member asked that the draft NEPOOL comments be made available for review in advance of the September 27 meeting.

Budget & Finance Subcommittee. Mr. Dell Orto reported that the Budget & Finance Subcommittee was scheduled to meet on October 7 to discuss the ISO's Capital Funding Tariff filing and to review some proposed Financial Assurance Policy changes.

GIS Agreement Working Group. Mr. David Cavanaugh reported that the NEPOOL Generation Information System (GIS) Agreement Working Group would meet by teleconference on September 12 to discuss options in light of the potential expiration of the GIS Development and Administration Agreement on December 31, 2016. Although the current agreement was scheduled to expire at the end of the year, it could be automatically extended one year, absent affirmative action by either APX or NEPOOL to not extend that agreement. He reported that the working group had identified and was considering options for extending the Agreement by one, two, or three or more years, with the inclusion of some additional commercial and technical terms developed by the Working Group, to potentially be followed by an open solicitation for the provision of administration services. The Working Group had also reached out to seek ISO input as to other options. Mr. Cavanaugh stated the Working Group was working towards a recommendation for Markets Committee, and ultimately Participations Committee consideration.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting was scheduled for October 14 at The Colonnade Hotel in Boston. He asked members to mark their calendars for the November 4 meetings with ISO Board members, state officials, and FERC representatives to be held in Windsor Locks, Connecticut at the Sheraton Bradley Hotel. He encouraged members to confer with their Sector Vice-Chairs on the questions/issues to be addressed in those meetings, reminding them that the ISO would request that information be provided in advance to allow the Board an opportunity to review that information before and prepare for the meetings. He also reminded the Committee of upcoming IMAPP meetings, September 14 and October 6 at the Doubletree Hotel in Westborough, and October 21 at the Renaissance Hotel in Providence, encouraging those who planned to bring attendees that do not normally participate in NEPOOL meetings to inform NEPOOL Counsel so that suitable arrangements could be confirmed.

There being no further business, the meeting adjourned at 12:25 p.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
SEPTEMBER 9, 2016 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Michael Lynch (tel)	
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID (CMP/UI)	Transmission			Alan Trotta (tel)
Belmont Municipal Light Department	Publicly Owned		Tim Hebert	
Boylston Municipal Light Department	Publicly Owned		Tim Hebert	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier		Brett Kruse	Bill Fowler
Chester Municipal Electric Light Department	Publicly Owned	Tim Hebert		
Chicopee Municipal Lighting Plant	Publicly Owned		Michael Lynch (tel)	
CLEAResult Consulting, Inc.	AR			Paul Peterson (tel)
Concord Municipal Light Plant	Publicly Owned		Tim Hebert	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User			David Thompson (tel)
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Danvers Electric Division	Publicly Owned		Tim Hebert	
Direct Energy Business, LLC	Supplier			Nancy Chafetz
Dominion Energy Marketing, Inc.	Generation	Jim Davis (tel)		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Maine	Transmission		Jose Rotger	Stacy Dimou (tel) Sandi Hennequin
Entergy Nuclear Power Marketing, LLC	Generation		Ken Dell Orto	
EnerNOC, Inc.	AR	Herb Healy		
Essential Power, LLC	Generation		Bill Fowler	
Eversource Energy	Transmission	James Daly	Cal Bowie	
FirstLight Power Resources Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Tim Hebert	
Groton Electric Light Department	Publicly Owned		Michael Lynch (tel)	
Groveland Electric Light Department	Publicly Owned		Tim Hebert	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User			Roger Borghesani Paul Peterson (tel)
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Tim Hebert	
Holden Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
Holyoke Gas & Electric Department	Publicly Owned			Michael Lynch (tel)
Hull Municipal Lighting Plant	Publicly Owned		Michael Lynch (tel)	
Ipswich Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
Jeffrey A. Jones, P.E.	End User	Jeff Jones (tel)		
Long Island Lighting Company (LIPA)	Supplier		Bill Killgoar	
Littleton (MA) Electric Light & Water Department	Publicly Owned		Tim Hebert	
Mansfield Municipal Electric Department	Publicly Owned		Michael Lynch (tel)	
Marblehead Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett		
Mass. Development Finance Agency	Publicly Owned		Tim Hebert	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Michael Lynch (tel)		
Merrimac Municipal Light Department	Publicly Owned		Tim Hebert	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
SEPTEMBER 9, 2016 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Middleborough Gas and Electric Department	Publicly Owned		Michael Lynch (tel)	
Middleton Municipal Electric Department	Publicly Owned		Tim Hebert	
National Grid	Transmission	Tim Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski		Brian Forshaw David Mullett Michael Lynch (tel)
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson (tel)		
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing LLC	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Tim Hebert	
Paxton Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
Peabody Municipal Light Plant	Publicly Owned		Michael Lynch (tel)	
PowerOptions, Inc.	End User	Cindy Arcate (tel)		
Princeton Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America Company	Supplier	Sam Moreton (tel)	Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Tim Hebert	
Russell Municipal Light Department	Publicly Owned		Michael Lynch (tel)	
Shrewsbury Electric & Cable Operations	Publicly Owned		Michael Lynch (tel)	
Small Renewable Generation Group	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Michael Lynch (tel)	
Sterling Municipal Electric Light Department	Publicly Owned		Michael Lynch (tel)	
Stowe Electric Department	Publicly Owned		Tim Hebert	
SunEdison (First Wind Energy Marketing, Inc.)	AR			Bob Stein, Abby Krich
Taunton Municipal Light Department	Publicly Owned		Tim Hebert	
Templeton Municipal Lighting Plant	Publicly Owned		Michael Lynch (tel)	
The Energy Consortium	End User	Roger Borghesani		Paul Peterson (tel)
Utility Services, Inc.	End User			Paul Peterson (tel)
Vermont Energy Investment Corporation	AR			Paul Peterson (tel)
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas and Light Department	Publicly Owned		Michael Lynch (tel)	
Wallingford DPU Electric Division	Publicly Owned	Tim Hebert		
Wellesley Municipal Light Plant	Publicly Owned		Tim Hebert	
West Boylston Municipal Lighting Plant	Publicly Owned		Michael Lynch (tel)	
Westfield Gas & Electric Light Department	Publicly Owned		Tim Hebert	
Wheelabrator North Andover Inc.	AR	Bill Fowler		

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