FINAL

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, May 2, 2014 at The Seaport Hotel & World Trade Center, 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. Joel Gordon, Chairman, presided and Mr. David Doot, Secretary, recorded. Mr. Gordon welcomed the members, alternates and guests who were present.

APPROVAL OF MARCH 7, MARCH 21, AND APRIL 4, 2014 MEETING MINUTES

Mr. Gordon referred the Committee to the preliminary minutes of the March 7, March 21, and April 4, 2014 meetings that were circulated and posted with the meeting materials. Following motion duly made and seconded, the preliminary minutes of the March 7, March 21 and April 4, 2014 meetings, in the form last posted before the meeting, were unanimously approved.

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.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Raymond Hepper, on behalf of Mr. Gordon van Welie, referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the April 4,

2014 meeting, which were circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

NESCOE REPORT ON GOVERNORS' INFRASTRUCTURE INITIATIVE

Ms. Heather Hunt, Executive Director, New England States Committee on Electricity (NESCOE), referred the Committee to the materials regarding the Governors' Infrastructure Initiative that were circulated and posted in advance of the meeting. She explained that the presentation contained a summary of the State Officials' meetings with the NEPOOL Sectors, an update on continuing State discussions, and NESCOE's request for feedback on the Incremental Gas for Electric Reliability (IGER) concept (Concept). She reported the States met with each of the NEPOOL Sectors on March 31 and April 14 in Boston. On behalf of the States, she thanked the Sectors for their time and care in preparing for, and participating in, the meetings. She summarized some of the common points shared with all the Sectors, including:

- New England had an infrastructure problem to solve.
- The infrastructure problem was presenting problems for both reliability and economic competitiveness.
- The States had sought more market-based approaches and other alternatives given the nature of New England's competitive markets.
    - Operational and economic pressures presented by the infrastructure challenges continued to exist and were increasingly acute despite previous identification and lengthy discussion of potential approaches/alternatives to solve those challenges.
    - The States welcomed suggestions on how to mitigate market implications associated with any proposed solutions to the infrastructure problem.
    - The States welcomed any ideas to ensure that future infrastructure requirements would be satisfied by the market without the need for State intervention.
- ISO-NE had expressed a very strong preference to remain neutral in the marketplace and not to interfere in the operation of the market.

The Committee members commented and asked clarifying questions. A Generator representative reviewed two issues of concern for that Sector: (1) comments made by a New England regulator during the State Officials' meeting with generators/long suppliers suggesting that the proposal was intended to primarily address pricing, rather than reliability concerns; and (2) the broadly-held concern of generators and long suppliers that the ISO Tariff was not an appropriate mechanism to use to subsidize the cost of new gas pipeline capacity. He suggested that, before presenting proposed changes to NEPOOL, the States consider explaining how concerns with the Federal Power Act and FERC precedent would be overcome, and strongly recommended that the States seek alternative means to achieve their objectives that would be more in keeping with FERC law and precedent. Ms. Hunt responded that the States all believed that there was a persistent, significant and continuing reliability issue and system stability issue. On how those reliability concerns were weighed relative to economic concerns resulting from geographic differentials in gas prices, Ms. Hunt explained that public officials necessarily must consider the effect on consumers of high and volatile prices. How any one state representative may communicate at a meeting the importance of this consideration versus reliability concerns cannot and should not be considered out of context of everything else being discussed at the meeting. It was not the view of NESCOE, the six states, or the six Governors that economic considerations override or were paramount to the reliability and system stability issues. She acknowledged the litigation risk associated with the approach, but that risk would not deter or delay the States' efforts to resolve their concerns.

A Supplier representative noted that the summary did not reflect an important expressed concern that, if this program were to go forward and the States were to be successful in developing pipelines, that Suppliers be informed of rate impacts well in advance so charges

assessed to them could be reflected in their transactions. Ms. Hunt responded that the States heard that concern and she would convey that concern to representatives that were not at the meeting.

An End User member suggested for consideration the approach employed in World War II when the Government needed pipelines between Texas and the Northeast that were built with Government backing and then sold at the end of the war, resulting in the beginning of the interstate natural gas pipeline system. He stated that, if such a solution were applied here, and if there was a loss upon the sale of a pipeline, only the loss would need to be socialized. A member highlighting climate policy expressed concern that the proposal to build infrastructure to meet short-term needs may be inconsistent with long-term needs, with resulting stranded costs. He recommended that changes be made incrementally and in phases to relieve the problem, while simultaneously working through market reforms. He worried that pursuit of a single, one-step solution was discouraging incremental gas solutions. A member opined that there were too many proposals that did not fit together; the region needed an overall approach with a timeline that incorporated energy efficiency, renewables, transmission, and reliability and should work to avoid the need for repetitive short-term solutions to winter reliability concerns. A Generator representative suggested for consideration that the States pay for new infrastructure and then immediately auction off the new infrastructure to the market. In that way, the new owner(s) could immediately employ the pipe in the market and manage its use under existing regulation.

Another Supplier member urged that the States help address price formation issues in the energy and capacity markets, adding that, unless the competitive markets provided adequate revenue to support necessary bulk power facilities, more and more out-of-market solutions

would be needed and the markets would collapse. Ms. Hunt stated the States heard very clearly the price formation arguments at the Sector meetings and were thinking hard about that issue.

Following up on prior stated positions, a Generator representative reiterated the concern about a State proposal challenging consideration of other market solutions. The Algonquin Incremental Market (AIM) Project and Atlantic Bridge Project were mentioned, along with reports that those projects might proceed without State involvement and they should be allowed to do so. He added that continued efforts on the NESCOE proposal, though, would provide disincentive for the pipelines to move ahead with their projects. Further, this representative urged that there be a clear determination as to whether the changes were to assure reliability or, instead, to change economics. If the issue was reliability, he suggested that there were other solutions that would not require new pipeline available 365 days a year. In response, Ms. Hunt explained that the proposed solution was clearly to address both reliability and economic issues that were largely inseverable. She acknowledged and shared concerns about the impact of new infrastructure on markets, but the States were resolute in solving soon the acute problem from both an economic and reliability perspective.

Ms. Hunt then reviewed the current status of the States' reconsideration of two proposed options: (1) no and/or low carbon resources, and (2) natural gas pipeline. She reported that the States continued to work through issues of cost allocation, with the expectation that there could be consensus in the near term. She outlined the key components of each option:

<u>No and/or Low Carbon Resources</u>

- One-time solicitation for incremental transmission anticipated, with costs shared across the region.
- Electric Distribution Company (EDC) participation in solicitation, with some states statutorily requiring such participation. States were developing proposals to address EDC conflicts of interest.

- Associated power agreement costs would be borne by those in states that choose to enter into such contracts.

Natural Gas Pipeline

- One-time solicitation for incremental capacity anticipated.
- Proposals to evaluate the cost of adding capacity to achieve desired import capability to be requested.

Ms. Hunt referred the Committee to the States' request for input on the IGER Concept, intended to help support electric power system reliability, circulated in advance of the meeting, noting it was at that point only a concept. She stated that NESCOE was interested in feedback on the approach generally and sought suggested alternative structures to that approach. She explained that the States were also interested in hearing about the desired characteristics for the various entities identified on the IGER Concept flow chart. Examples of such characteristics could include the ability to comply with Tariff requirements, accountability, ability to transact business transparently, and any other characteristics the States should consider. Regarding market implications, the States welcomed and encouraged common means to structure the concept to minimize market distortions. In response to the EDC's April 22, 2014 letter to NESCOE on the utility proposal for a potential path forward, the States were interested in input on that, conceptually or in a detailed way, and on any element of their proposal. She also requested any suggested market mechanisms to eliminate the need for state action be identified. She reported the States presently intended to advance a proposal to NEPOOL for discussion in June, with a goal of a Participants Committee vote in September. She requested that, since time was of the essence, any comments be forwarded to RegionalInfrastructure@nescoe.com as soon as possible.

Mr. Gordon reviewed that the proposed process for Participants Committee consideration in September would entail having discussions in June at the Transmission Committee on

proposals that come forward and would involve other Technical Committees for their engagement at that time and over the summer.

The Committee then commented and asked clarifying questions on the process and update summary. In response to a question concerning new transmission cost allocation, Ms. Hunt explained that each State would determine whether long-term imports to flow over any new transmission would be desired for the State, and transmission costs would then be covered by load in those States. It would be up to the States to determine how the power costs, aside from transmission costs, would be allocated.

A Supplier Sector member asked that the legality of the proposed approach be determined first before taking valuable time from the Technical Committees, as that time would and should be spent implementing the ISO's strategic plan to address the very problem that the States were concerned about. Ms. Hunt responded that the States were very sensitive to making sure that whatever they bring forward was developed enough that it merits Technical Committee time, but early enough so that the final solution could be determined with the benefit of full Technical Committee input. To accomplish that result, NESCOE would talk in advance about the proposal to make most efficient use of the Technical Committee's time. She expressed a willingness to make time for a threshold discussion of legal issues.

In response to a question as to the involvement of local gas distribution companies (LDCs), Ms. Hunt reported that the States were talking to stakeholders, one-on-one and in groups, and the LDCs were among those being consulted. She said also that NESCOE's request for comment was also circulated for input to the New England Gas-Electric Focus Group, which included many from the gas industry.

A member commented that the IGER Concept implicated challenging legal issues concerning the use of the ISO's Transmission Tariff to pay for non-transmission alternatives and the range of what those funds could be used to pay for. By trying to solve one problem, he cautioned the region against creating another. He urged the States to determine whether the incremental gas projects in response to existing market signals were being slowed or chilled by these discussions, and if so, to consider pausing to see how the market-based projects proceeded. Ms. Hunt responded that the States had not, individually or collectively, been willing to delay, as they believed the reliability and economic competitiveness pressures to be acute. Addressing the use of the Tariff, she stated that there was a regional electric problem and the benefits would flow to regional electric ratepayers. Matching costs to regional beneficiaries was both desired and sensible.

The Committee discussed whether the Markets Committee should be involved in addition to the Transmission Committee. Mr. Gordon explained that the NEPOOL Officers directed that consideration of this issue start with the Transmission Committee because the proposal was to amend the Transmission Tariff. The Markets Committee and the Budget & Finance Subcommittee would also necessarily be involved with the discussions.

A member sought clarification on the specific input NESCOE was seeking regarding the IGER concept and alternatives. Ms. Hunt responded that the States were seeking general reaction or comments before proceeding to the next level of detail. She invited entities that believed they were well-suited for one of the identified roles or had suggestions on the kind of entities that the States should be talking to or thinking about, to provide NESCOE that input. A member expressed concern that the proposal created preferential treatment for natural gas-fired generators to the detriment of other resources.

Mr. Gordon concluded the discussion by reminding the Committee that a status update on this issue would be provided at the June Participants Committee meeting, and urged Committee members to provide any feedback and comments directly to NESCOE.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the May COO report regarding April operations, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing on highlights, he stated that, in April: (i) natural gas average prices were 67% lower than March average prices; (ii) Real-Time Hub locational marginal prices (LMPs) on average were 64% lower than March LMPs; (iii) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 98.8% in April, versus 98.1% in March; (iv) daily NCPC, totaling $5.7 million, was $12.2 million lower than March NCPC; (v) first contingency payments, totaling $2.5 million, were $13.4 million lower than March's; (vi) second contingency payments totaled $2 million, which was $5,000 lower than in March; and (vii) voltage support payments totaled $843,000 compared to March when there were no such payments.

Looking forward to Summer 2014, Dr. Chadalavada reported that the ISO was forcasting a normal summer peak demand of 26,658 MW and an extreme peak demand of 28,884 MW for the week beginning July 13, with a projected net margin at that time of 1,687 MW. He said ISO expected an additional 300 MW in load reductions from energy efficiency programs over the summer. He reported that two fossil fuel units (Salem 3 and 4), which had a total nameplate capability of 585 MW, were scheduled to retire by June 2014. Looking ahead to Summer 2015, he reported that construction on the AIM pipeline project was expected to result in tight

conditions for natural gas supply during that summer. He said that the ISO would work to coordinate with all impacted parties in order to minimize reliability concerns.

Dr. Chadalavada was asked about the requirement that capacity bidders provide fuel availability information in their New Qualification Packages for the next Forward Capacity Auction due June 17. Dr. Chadalavada explained in response that the ISO did not consider this a new requirement, as the existing and unchanged qualification process required the ISO to make sure that the resources that qualify to participate in the auction were deliverable and could produce energy to serve load. He said the ISO was seeking to determine whether new gas plants would merely displace gas that was already being used to meet regional need, particularly the need for energy in the winter months. The member requested that the ISO tell Market Participants as soon as possible what, and in what form, the information would need to be provided so that bidders could begin assembling the necessary information.

In response to clarifying questions on the impact of the AIM pipeline project on Summer 2015 operations, Dr. Chadalavada explained that there may also be simultaneous maintenance outages for other pipelines during AIM project construction, so the ISO was working to coordinate with all the pipelines so overlap of the maintenance outages do not occur during a projected peak load week. He added that, to the extent that the outages were projected to impact specific generators, the ISO intended to work with the impacted generators so that appropriate dispatch decisions could be made. It was clarified that an adequate supply of gas for the region was expected, but there could be some locational issues, with certain plants affected by the constraints. The ISO committed to monitor the situation closely and to advise if this appeared to become a regional problem, rather than a locational problem.

ISO IMM QUARTERLY MARKETS REPORT (2014 Q1)

Mr. David LaPlante, ISO Internal Market Monitor (IMM), referred the Committee to the presentation circulated and posted in advance of the meeting regarding the 2014 1st Quarter (Q1) Quarterly Markets Report. Before reviewing the report, he introduced and welcomed Mr. Jeffrey McDonald to the Committee, reporting that Mr. McDonald would begin as the new ISO IMM in early June. He noted that Mr. McDonald would be at both the New England Conference of Public Utilities Commissioners, Inc. (NECPUC) Symposium and the Participants Committee Summer Meeting in June.

Mr. LaPlante reported that the 2014 Q1 Energy Market prices were consistent with those expected from a competitive market. He reported also that the IMM concluded that the Energy Market was generally unconcentrated and structurally competitive. Providing more detail, he explained that energy prices largely reflected supplier short-run marginal costs and, when needed, mitigation rules provided adequate behavioral remedies.

Mr. LaPlante highlighted market outcomes and a summary of wholesale market costs, reporting that higher natural gas prices in 2014 Q1 led to higher Day-Ahead and Real-Time Energy Market prices when compared to 2013 Q1 and 2013 Q4. He reported that, on average, the price of gas exceeded the price of oil in 2014 Q1. He reported also that there had been $107.1 million of NCPC payments during 2014 Q1, which was 43% greater than 2013 Q1. A member asked whether the IMM had compared the impacts of gas prices in New York and PJM to those in New England to assess whether the corresponding increases were similar in all the RTOs. Mr. LaPlante responded that the IMM had not performed such an assessment.

Mr. LaPlante reported that $14.7 million in Real-Time Reserves payments were made in 2014 Q1, a 158% increase from 2013 Q1, explaining that those increased payments coincided with increases in the amount of Reserves purchased in the Forward Reserve Market, for Real-

Time Reserves, and for Replacement Reserves. He reported Regulation payments totaled $15.8 million in 2014 Q1, as compared to $6.5 million in 2013 Q4, with the increase driven by higher Real-Time Energy Market prices which, in turn, created higher Regulation service and Regulation Opportunity Costs. He reviewed a chart showing that there were no supplemental commitments on most days during the quarter, but that there had been one day in January with supplemental commitments of approximately 3,000 MW, accounting for a majority of the quarter's uplift.

Turning to an analysis of estimated oil unit infra-marginal rents (IMR) from December 2011 through January 2014, Mr. LaPlante explained that the analysis focused on 17 oil-only units with a capacity rating greater than 50 MW, which represented in total approximately 3,460 MW of capacity. He said that adjustments were made to the IMR calculation for units that were self-scheduled or that submitted offers less than the IMM's estimate of marginal costs, setting IMR in those instances to $0. He referred the Committee to a chart of that analysis, which calculated the IMRs as follows:

- $2.5 million December 2011- January of 2012;
- $18 million December 2012 – January 2013;
- $138.6 million December 2013 – January 2014;
- $35.1 million calendar year 2012; and
- $79.3 million calendar year 2013.

Mr. LaPlante concluded that the oil units were earning positive IMRs, but the difference between Winter 2011/12 and Winter 2013/14 was especially striking. The more recent numbers appeared to provide economic incentives in the future for owners to procure oil for the winter. Because of the risk to the system of insufficient oil, he suggested that the ISO and customers might want higher oil inventories than might otherwise be economically justified. This desired outcome was

the reason the ISO was pursuing a winter program for Winter 2014/15. A member, based on this observation, questioned how such action would satisfy the FERC directive that future winter programs be more fuel neutral. Mr. LaPlante responded that the ISO had not identified an acceptable design that was workable at a reasonable price for natural gas.

ISO REPORT ON WINTER 2013/14 OPERATIONS

Dr. Chadalavada referred the Committee to the ISO presentation circulated and posted in advance of the meeting regarding Winter 2013/14 Operations. In follow up to a question from the April 2 Committee meeting regarding how much oil was actually burned during Winter 2013/14 (December 1, 2013 through February 28, 2014), he reported that 2.7 million barrels of oil were burned, noting it would have been 3.2 million but for the forced outage of a fairly efficient plant. By way of comparison, he said that analysis indicated that only 1.6 million barrels of oil were available in December 2012. The ISO concluded that the Winter Program was effective in assuring winter reliability.

Dr. Chadalavada explained that, for planning purposes, the ISO was reflecting on lessons learned from Winter 2003/04, when there had been more extreme cold, but for shorter periods of time. In contrast, Winter 2013/14 saw extended cold weather (20-25 days), but less extreme cold temperatures. He reported that Winter 2013/14, as measured by heating degree days, was the 3rd coldest winter in the past 20 years, and Winter 2003/04 was the 6th coldest winter. The ISO needed to be prepared to address reliability concerns in either scenario.

Regarding uncertainties and challenges faced by Control Room operators, he reviewed a chart illustrating Limited Energy Generation (LEG) usage on demand days in late January by oil and gas units that used the LEG flag as a way to convey to the Control Room that their energy production might be limited below their economic maximum (EcoMax). He stated this flag was

useful for the operators because it allowed for planning and preparation to address the uncertainty of supply. He reported that during the six days of greatest pipeline constraints, between 92-96% of pipeline was fully committed, with several other days where commitment was at 88-90%. He reported that, on January 3, 2014, there was 4.5 million Bcf of operating capacity with only 200 MMcf available and unused or unscheduled. Of that, only 500,000 MMcf was going to the gas generators, with almost everything else going to the LDCs or to New York.

In follow up to Participant requests, Dr. Chadalavada reviewed charts illustrating that the energy produced by natural gas generators from pipeline gas over the coldest 20 days totaled 1.5 million MWh versus 1.1 million MWh produced by oil generation from resources participating in the Winter 2013/14 Reliability Program. He shared observations on outages, including:

- A number of large units were out of service during cold spells:
  - A 600 MW dual-fuel unit was out from mid-December to early February
  - A large coal unit missed most of the January 21-28 cold weather
  - Two oil units (400+ MW each) missed parts of both January cold spells
  - Another coal unit had been out of service since early January
- There were a number of cold days with significant unplanned outages.

Regarding oil units that were in merit, he reported gas prices exceeded oil prices on 57% of the winters' days, as compared to 18% during Winter 2012/13. He reported that Participants, States, federal policy officials, and congressional delegates had all raised questions concerning the causes of price spikes even on days when temperatures were relatively moderate. He said the trend of volatility and high prices was steadily worsening each year. He explained the additional pressure experienced by oil resources that were increasingly expected to be in-merit and available on an increasing number of days, which magnified concerns on their readiness for such use during upcoming winters.

A member commented that the information reflected in the presentation was widely disseminated and improperly implied greater impact on consumers. He said the reality was that many customers' bills were unaffected because their competitive retail supplier had been hedged against the price volatility. He urged, and Dr. Chadalavada agreed, that, in future presentations, the ISO would make clear that the reporting was at the wholesale spot market level.

Dr. Chadalavada next focused on the effectiveness of many of the reforms in place for Winter 2013/14, including: replacement reserve pricing, tighter FCM shortage event triggers, and accelerated Day-Ahead Energy Market (DAM) timing. With regard to the DAM timing, he stated the ISO issued a report and would circulate an updated version that included the review of the past 6-7 months for potential review at a Technical Committee meeting. On Replacement and Operating Reserves performance, he reported that, with additional Replacement Reserves, when the Replacement Reserve constraint was binding or violated, the ISO and the market had an earlier indication that the System was approaching scarcity conditions. He reported that between December 1, 2013 and February 28, 2014, there were 40 hours during which the Replacement Reserve Reserve Constraint Penalty Factor (RCPF) was binding for at least one interval, but not violated; 25 hours where the Replacement Reserve RCPF was violated for at least one interval; 16 hours where the Thirty-Minute Operating Reserves (TMOR) were violated for at least one interval; and 3 hours where Ten-Minute Non-Spinning Operating Reserves (TMNSR) was violated for at least one interval. He noted the improved price signals for performance at times when the System was most constrained.

Dr. Chadalavada next reported on net imports into New England on the coldest days in Winter 2013/14. He highlighted the variability between what imports cleared Day-Ahead and what actually flowed in Real-Time. He said some days' imports were much greater than

scheduled and other days much less and explained the planning challenges presented. He further explained the need for confidence that reliability would not be compromised and market efficiency would be maintained in either scenario. He clarified in response to a question that much of the variability was attributed to economy energy. He said that conditions outside New England can also significantly affect New England because economy energy imports could be curtailed at any time for contingencies outside of New England. He reported, also in response a question, that capacity-backed import transactions, often totaling no more than a few hundred megawatts, almost always flowed, and could be counted on to be were delivered as, and when, needed. A member asked whether a distinction could be drawn as to the impacts on the different ties into the region (e.g., imports from New York on the AC ties versus imports over the HQ Phase II ties). Dr. Chadalavada stated that the ISO did not break the data down that way, but could look back at several days experiencing the biggest swings in order to assess whether there was a meaningful difference.

Dr. Chadalavada reported that the most significant market improvement scheduled for implementation for Winter 2014/15 was the Offer Flexibility project. He stated that the planned project implementation date was December 1, 2014, and the ISO would provide an update on the status of that project in June.

Turning to a summary of the ICF Analysis that was discussed at the Planning Advisory Committee (PAC) meeting, Dr. Chadalavada said that ICF updated its model to reflect better flows from the liquefied natural gas (LNG) terminals and general LDC demand. ICF projections now, with which the ISO agreed, then showed that, for Winter 2014/15, gas for electric production could be expected to fall below 1,000 MMcf/d for 45 days, and below 500 MMcf/d for 20 days. He stated that the trends indicated that most of the existing pipeline capacity was

used to meet increased demand from LDCs. In short, the region should be prepared for less gas available to gas generators during Winter 2014/15.

A member highlighted the following caveats covered as part of the ICF Report at the PAC meeting:

- Available gas was suppressed partly by the Winter Reliability Program since power plants were running on oil that might otherwise have drawn gas that could have come LNG terminals.
- The market distorting effect of the Winter Reliability Program was unknown.
- Past performance may not be a good indication of what would happen in the future.
- For planning purposes, because of changes in the gas and the oil markets, the specific phenomena witnessed during Winter 2013/14 would not necessarily be predictive of Winter 2014/15.

Dr. Chadalavada commented that all oil resources that ran during Winter 2013/2014 were in-merit. In a well-functioning market, the ISO would expect oil resources to run in-merit when gas prices peak to the levels experienced. He stated that from a reliability standpoint, the ISO must plan for the possibility that last winter's experiences were in fact a good indication of what could happen in Winter 2014/15. A member commented that there was a big gap between the two lines but that the gap shrunk considerably on the coldest days. Assuming that the coldest days were the highest priced gas days, the chart becomes effectively a price chart. Dr. Chadalavada countered that the chart was more than just a price chart, illustrating also market dynamics experienced. He offered to further discuss the chart off-line.

Dr. Chadalavada concluded the Winter 2013/14 Operations report by expressing appreciation to the Committee for all the questions that were submitted and to Ms. Allison DiGrande and ISO staff for collecting and assembling responses to the inquiries.

SUPPLEMENTAL WINTER 2014/15 RELIABILITY PROGRAM

Dr. Chadalavada then provided an overview of the ISO's Winter 2014/15 Proposal. He identified recent experiences that weighed against implementing another Winter Reliability Program, including the FERC's order clarifying generators' obligations and the accounting for anticipated benefits of the Offer Flexibility changes. Weighing in favor of a Winter 2014/15 Reliability Program were the following:

- Increased gas pipeline constraints;
- Retirements of non-gas-fired generators (Vermont Yankee and Salem Harbor) that together were capable of producing 2.6 million MWh when both were operating; and
- Difficulties replenishing oil supplies experienced during Winter 2013/14.

On balance, he explained, the ISO concluded it was wise to consider with stakeholders a proposed modified program for the upcoming winter that included the following three components: (1) incentives for dual-fuel capability; (2) payment for unused oil inventory; and (3) a demand response program. He stated that ISO's objectives for the Winter 2014/15 Proposal would be to implement a program with lower up front incentives to generators to stock up on fuel ahead of the winter, but would be designed to increase incentives to dual-fuel units by reducing the risk to generators for carrying unused fuel inventory at the end of the winter. He said that the ISO's proposal was informed by discussions with almost all of the major New England suppliers concerning their experiences during Winter 2013/14. Those discussions led the ISO to propose a program designed to increase incentives for on-site dual-fuel units and to decrease the separate incentives for fuel replenishment.

Committee members asked questions and commented on the Winter 2014/15 Proposal. A member urged the ISO to ensure that its recommended program provided sufficient incentive to achieve the desired objectives. Dr. Chadalavada explained that, based on the experiences

during Winter 2013/14, the ISO intended the incentives to be sufficient to result in about three million barrels of oil available for Winter consumption. Another member questioned whether the ISO was scaling back with such a target. Dr. Chadalavada responded that the ISO was scaling back by proposing program payments to cover inventory at the end of the winter rather than paying for initial inventory and replenishment, as the ISO had done during the prior winter. In response to the ISO's conclusion as to the impact of the FERC's clarification of generator obligations, Dr. Chadalavada explained that the FERC order was too late to directly impact Winter 2013/14 operations. The ISO did think the order would help and would not be seeking further clarification, but concluded it must plan for generator performance nonetheless that was similar to that experienced for the Winter 2013/14 Program. A member asked what changes might obviate the need for a winter reliability program. Dr. Chadalavada responded that a winter program may prove unnecessary with appropriate FCM reform and market design improvements to ensure that all energy would be valued equally, regardless of how produced. He explained that, for the next three to four years, the ISO expected that many New England resources would display some attributes of Limited Energy Resources.

In response to further questions, Mr. Hepper confirmed that the ISO interpreted the FERC order on generator obligations to mandate that oil units maintain sufficient oil inventory to meet their Day-Ahead schedules, with sanctions possible if they did not. He suggested that such an expectation, though, may not be enough to maintain reliability because it could take the FERC two or three years to investigate and take action on a failure to maintain inventory, with controlled outages unavoidable in the meantime. In response, at least one member stated opposition to any out-of-market incentives for Winter 2014/15 if oil unit obligations were

sufficient and clear. Dr. Chadalavada concluded this line of questions by explaining that the ISO was, and would continue to be, biased in favor of maintaining reliability.

A member complained that the 2013/14 Winter Program created market chaos because it was expensive, was adopted very late in the process, and much winter business was adversely impacted by the FERC's rejection of the recommended allocation of the costs of the Program. He urged that details concerning the Winter 2014/15 program be identified quickly, and at the very least identify whether the program would be market-based or cost-of-service based. Dr. Chadalavada indicated that the ISO was favoring a cost-of-service model, with a set rate much like a VAR payment. He stated the ISO would be working through those details in the next two weeks. In response to a member's question as to whether the ISO had considered proposing a three-year program, Dr. Chadalavada acknowledged that ISO was looking to maintain a program in place until a superior alternative was implemented. The FERC decision on FCM performance incentives could influence how the ISO would proceed and any future winter reliability program.

Turning to details regarding the proposal, a member asked whether the proposed payment for unused oil inventory would be an additional payment during Winter 2014/15 solely for dual-fuel units. Dr. Chadalavada responded that the proposal would make program payments available to oil-only and dual-fuel units, and there would be additional incentives that would be made permanent for dual-fuel units.

A member identified the substantial lost opportunity to resources that did not have fuel, and asked why the Energy Market was not incentive enough to achieve the desired objective. Dr. Chadalavada responded that, in light of the experiences of Winter 2013/14, the ISO had concluded that it could not be sufficiently satisfied that such market incentives would be enough to address weather uncertainty. A member asked for clarification as to the ISO's view as to any

difference between the obligations of oil and dual-fuel resources, whether in the program or not, on the one hand, and those of gas-fired resources on the other. Dr. Chadalavada responded that the ISO was trying to avoid differentiating between oil and gas as much as possible, but recognized the FERC's clarification that gas-fired units were excused from performance if the attributes of the gas markets precluded such units from sourcing gas, either because the physical commodity or transportation was not available.

Turning to questions on implementation, a member observed that, notwithstanding the proposed program's potential for positive results, particularly for dual-fuel resources, participation would be constrained by the timing of the proposal and subsequent FERC action. Dr. Chadalavada acknowledged the timing challenges, which the ISO hoped to mitigate in part by establishing deadlines that would permit dual-fuel resource participation in future Winter periods.

Another member expressed a concern with a perceived lack of sufficient, technology-neutral, market-based elements that would permit all resources, particularly those with multi-year fuel inventories, to participate in the program. In response, Dr. Chadalavada clarified that the FERC's order on performance incentives would impact how the ISO would proceed in the future, but until that decision was issued, the ISO would act based on the information it had, and would adjust its actions, if and as necessary, based on the FERC's order. He highlighted the ISO's dedication to market efficiency (highlighting energy offer flexibility changes and Ancillary Services reforms as illustrative), but contended that near-term challenges would require solutions not wholly achievable through market design changes. The ISO's proposal for Winter 2014/15 was to minimize market interference and the size of program payments, and to

ensure that that Energy Market payments continued to be the primary basis for forward decision-making.

Following an ISO acknowledgement that the proposal could increase reliance on oil, a member urged that the region take into account the health and environmental risks that had driven the market to reduced use of oil as a primary fuel in the first place. The ISO also explained in response to a question, that it was relatively certain that Vermont Yankee and Salem Harbor would not be kept in service for Winter 2014/15.

Dr. Chadalavada then summarized the following three components of the proposed Winter 2014/15 Program:

1. Incentives for Dual-Fuel Capability
    - Testing component – Resources to be required to maintain their dual-fuel capability for a set number of years or to repay testing costs
    - Re-commissioning costs to be offset through NCPC payments
    - Permanent Market Rule Changes – in competitive market conditions, dual-fuel resources clearing on higher cost fuel would not need to prove that high cost fuel was actually burned and dual-fuel units to be compensated for operational readiness audits
2. Payment for Unused Oil Inventory
    - To rely more on upfront inventory and less on replenishment, establish an administrative payment rate reflecting key risks associated with having unused oil at the end of the season, including:
        - Carrying costs
        - Depreciation in per barrel price of oil
        - Salvage costs
3. Demand Resource Program
    - Same general structure as Winter 2013/14 Program, but dispatch limited to six hours and frequency increased from ten to increase participation, risk of potential penalties that exceed revenues to be eliminated, and monthly payments based on set rate (instead of bid price).

In concluding his report, Dr. Chadalavada said that the ISO would present its proposal at the Technical Committees, with detailed discussions planned for May 6 and May 23 Markets Committee meetings, and additional details to be provided as received. Regarding questions concerning LNG, he reported that the ISO was working with the Analysis Group and looking at option contracts and take-or-pay contracts and was open to considering whether there might be a way to mimic for LNG the structure proposed for unused oil. A member requested that the ISO identify a ceiling on the total amount it would spend for the Winter 2014/15 Program. Another member urged that a discussion of more market-oriented approaches also take place. Mr. Gordon urged all those interested to participate in the planned Markets Committee meetings.

SUPPLIER SECTOR PROVISIONAL MEMBER GROUP SEAT PROPOSAL

Mr. Gordon reported that consideration of a proposal to create a Provisional Member Group Seat in the Supplier Sector was deferred to a later meeting. He stated the proposal would be discussed further at a special meeting of the Membership Subcommittee. NEPOOL Counsel was asked to send notice of that special meeting to all Participants Committee members and alternates. Mr. Gordon encouraged all members interested in participating in a discussion of the appropriate arrangements for developers or owners of Merchant Transmission Facilities (MTF) to attend that Subcommittee meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the May 1 Litigation Report that had been posted in advance of the meeting and encouraged anyone with comments or questions on the Report to please contact NEPOOL Counsel.

COMMITTEE REPORTS

Mr. Stephen Kirk reported that the NEPOOL Audit and Management Subcommittee (NAMS) was reconvening in order to perform an audit of the ISO and was scheduled to next meet on May 8. He reported that the purpose of the meeting was to begin to scope out what NEPOOL wanted to see audited and who would oversee the audit process. He encouraged all those interested to participate in that meeting.

OTHER BUSINESS

Mr. Doot referred the Committee to the NEPOOL calendar for May and June. He reported the next regularly-scheduled meeting of the Participants Committee would be held on June 6, 2014 at the Renaissance Providence Hotel in Providence, Rhode Island. He reminded the Committee of the need to register for the June 24-26, 2014 Participants Committee Summer Meeting at The Cliff House in Ogunquit, Maine, noting the Cliff House reservations cut-off date was June 12. He also reminded members of the Northeast Energy and Commerce Association (NECA) Annual Conference & Exhibition scheduled for May 13-14, 2014 in Falmouth, Massachusetts, the Consumer Liaison Group (CLG) meeting scheduled for May 29 at The Cliff House, and the NECPUC Symposium scheduled for June 15-18 at the Stowe Mountain Resort, in Stowe, Vermont.

There being no further business, the meeting adjourned at 1:56 p.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
MAY 2, 2014 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
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			Paul Dumais
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Cianbro Companies	End User			William P. Short III
Citigroup Energy Inc.	Supplier	Barry Trayers (tel)		
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			David Thompson
Conservation Law Foundation (CLF)	End User	Seth Kaplan	Jonathan Peress (tel)	
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			William P. Short III
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User			William P. Short III
Emera Maine, Inc.	Transmission	Jeff Jones (tel)	Stacy Dimou	
Energy America, LLC	Supplier	Ron Carrier (tel)		Nancy Chafetz
EnerNOC, Inc.	AR		Greg Geller	
Enerwise Global Technologies Inc.	AR		John Driscoll (tel)	
Entergy Nuclear Power Marketing Inc.	Generation	Marc Potkin		
EquiPower Resources Management, LLC	Generation		William Fowler	
Essential Power, LLC	Generation	M.Q. Riding (tel)	William Fowler	
Exelon Generation Company	Supplier	Steve Kirk	William Fowler	
Fairchild Semiconductor Corporation	End User			William P. Short III
First Wind Energy Marketing, Inc.	AR	John Keene		Francis Pullaro
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy (tel)	Abby Krich	
Georgetown Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault (tel)		Abby Krich
Hardwood Products Company	End User			William P. Short III
Harvard Dedicated Energy Limited	End User	Mary Smith		Robert Borghesani
Hess Corporation	Supplier			Nancy Chafetz
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
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	
IPR-GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Kimberly-Clark Corporation	Supplier			Elizabeth Trinkle (tel)

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
MAY 2, 2014 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
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		
Macquarie Energy, LLC	Supplier	Christi Nicolay (tel)		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden's Inc.	End User			William P. Short III
Mass. Attorney General's Office	End User		Christina Belew (tel)	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Gary Will		
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
MoArk, LLC	End User			William P. Short III
New England Power Company (National Grid)	Transmission	Timothy Brennan		
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski (tel)	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson	Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NU / NSTAR	Transmission		Calvin Bowie	Joe Staszowski
NRG Power Marketing, Inc.	Generation	Peter Fuller		
PalletOne of Maine	End User			William P. Short III
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cynthia Arcate		
PPL EnergyPlus, LC	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Elizabeth Trinkle (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		Dave Cavanaugh	
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User			William P. Short III
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			William P. Short III
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	Roger Borghesani	Mary Smith	
TransCanada Power Marketing Ltd.	Generation		Mike Hachey	
Union of Concerned Scientists (UCS)	End User	Paul Peterson		
United Illuminating Company (UI)	Transmission	Rich Peters	Alan Trotta	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori		Mark Sciarrotta
Vermont Energy Investment Corporation	AR		Doug Hurley	

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
MAY 2, 2014 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		
Vitol, Inc.	Supplier	Joe Wadsworth		
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			William P. Short III
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
Z-TECH LLC	End User			William P. Short III