FINAL

The 2017 Summer Meeting of the NEPOOL Participants Committee was held at The Chatham Bars Inn, Chatham, Massachusetts, on Tuesday, June 27, and Wednesday, June 28, pursuant to notice duly given, followed on Thursday, June 29, by meetings between modified sector groups and ISO Board Members, State Officials, and FERC representatives, respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 27. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. Thomas Kaslow, presided and Mr. David Doot, Secretary, recorded for the meeting.

JUNE 27, 2017 SESSION

EXECUTIVE SESSION

The June 27, 2017 session began at 9:30 a.m., with discussion in confidential Executive Session during consideration of a proposed slate for election/re-election to the ISO Board of Directors and the confidential proposed settlement of matters set for hearings in the Peak Energy Rent (PER) proceeding (Agenda Item Numbers 1 and 1A, respectively). Except as specifically noted, the only people present during the Executive Session discussions were members, alternates or those Participant representatives specifically designated by the members and alternates for attendance.

CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Mr. Kaslow introduced Mr. Paul Levy, Chairman of the Joint Nominating Committee (JNC), and Ms. Roberta Brown, JNC and ISO Board Member. Mr. Kaslow explained that the discussion of the slate of candidates would be in Executive Session in order to maintain in confidence the identity of those candidates being considered for membership on the ISO Board until there was a final ISO Board decision on the slate. Following general comments on the process, Mr. Levy identified the candidates, referring to the confidential package of materials that was circulated to the members and alternates of the Committee in advance of the meeting. He and Ms. Brown offered thoughts on the candidates and the nomination process and then left the meeting.

The slate was then discussed among the members and alternates. Separate from discussion of the candidates on the slate, a number of members noted that PJM members vote on board members on an individual basis rather than on a slate basis. The Committee discussed the history and rationale for NEPOOL's process. Based on the discussions, the Chairman proposed that the Officers consider this issue separately off-line and report back following that consideration.

Following further discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for NEPOOL endorsement, with the vote accomplished by secret written ballot per prior agreement of the Participants Committee:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in Executive Session at this meeting.

CONFIDENTIAL VOTE ON PER SETTLEMENT

Following that vote, parties in the pending Section 206 FERC proceeding concerning the FCM Peak Energy Rent (PER) mechanism, including representatives from the ISO, NEPGA and NESCOE, were invited to participate in the Executive Session discussion of a proposed settlement term sheet (the Settlement Term Sheet). Mr. Doot then referred the Committee to the confidential materials on this topic that were circulated to members and alternates in advance of the meeting and explained that, while each party to the settlement proceeding either joined in the submittal of the Settlement Term Sheet to Settlement Judge Young or had indicated nonopposition, the Settlement Term Sheet would need to be reflected in a formal settlement agreement that had yet to be finalized. He noted that the proposed form of resolution would delegate limited authority to the Officers to approve a final Settlement Agreement if that was the will of the Committee. He reminded the Committee that the settlement information was being presented confidentially and was privileged in accordance with the FERC's rules of practice and procedure and was not for further distribution.

The key negotiators of the PER Settlement then reviewed the terms with the Committee and responded to questions. Following full opportunity for questions and discussion, the Committee considered the following motion, which was duly made, seconded, and approved by a show of hands vote, with DTE opposing the motion and abstentions by: CMEEC, CLF, CSC, Galt, IECG, Just Energy, LIPA, Mercuria, NH OCA, NextEra, PowerOptions, Reading, Sun Edison, TEC, Utility Services, VEIC, Vitol, VPPSA, and the AR Sector's Small Load Response and Small Renewable Generation Group Members:

> RESOLVED, that the Participants Committee
>
> (1) supports the Settlement Term Sheet that comprehensively addresses all issues set for hearing in Docket No. EL16-120 (concerning the Peak Energy Rent mechanism in the Forward Capacity Market) (the Settlement Term Sheet), dated as of June 15, 2017, as circulated to the Committee prior to its meeting on June 27, 2017, and
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> (2) delegates to the officers of the Participants Committee the authority, subject to unanimous agreement, to approve a formal offer of settlement reflecting the Settlement Term Sheet, and to the Chairman of the Participants Committee the authority to execute that offer of settlement on behalf of NEPOOL, it being understood that a separate Participants Committee vote would be required if the officers do not unanimously agree on the offer of settlement.

RETURN TO GENERAL SESSION

The Committee came out of Executive Session at 10:30 a.m. and invited all other attendees into the room. Mr. Kaslow welcomed those participating in the Summer Meeting, including members, alternates, and guests, and recognized the ISO Board Members, State Officials, and FERC representatives in attendance. Mr. Doot announced publicly the results of the votes that occurred in Executive Session.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the written summaries of the ISO Board and Board Committee meetings that had occurred since the May Participants Committee meeting, which were circulated and posted in advance of the meeting. There were no questions or comments on the summaries. There was a discussion of press reports on his presentation at the June 12 Edison Electric Institute Annual Convention in Boston. He said he had expressed his views during a panel discussion that it would be particularly hard to accomplish, through competitive markets, material investment in networked infrastructure subject to open access requirements.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), then reviewed highlights from the June COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He explained that the report reflected data for the entire month of May. Focusing on highlights, he reported for May that: (i) Energy Market value was $283 million, up $3 million from April 2017 and up $67 million from May 2016; (ii) average natural gas prices were 4.7% lower than April 2017 average prices; (iii) average Real-Time Hub LMPs ($29.44/MWh) were 6.6% lower than April 2017 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 97.2% in May, up from 97% in April; (v) daily Net Commitment Period Compensation (NCPC) for May totaled $5.6 million, up $2.5 million from NCPC experienced in April 2017 and $3.6 million higher than NCPC in May 2016; (vi) first contingency payments, totaling $4.5 million, were $1.8 million higher than

April’s; (vii) second contingency payments totaled $1 million, up $987,000 from April 2017; (viii) voltage support payments totaled $73,000, down $298,000 from April’s; and (ix) NCPC payments were 2% of the total Energy Market value.

Turning to the average daily Day-Ahead cleared physical Energy, he observed that the percentage of load clearing Day-Ahead for peak hours had been dropping disproportionately. He explained that, while the statistics for May showed that 97.2% of load on average cleared Day-Ahead, there were several days where the load for peak hours that cleared Day-Ahead was more than 1,000 MWh below the actual Real-Time load. He stated that trend was even more pronounced in early June, with the difference between Day-Ahead and Real-Time loads exceeding 1,500-2,000 MWh. The ISO was considering the following possible explanations: (1) Market Participants, like the ISO, could be having difficulty forecasting Real-Time load accurately, given the penetration of photovoltaic (PV) resources; and (2) Market Participants might prefer to under-predict load, recognizing that there can be as much as 700-900 MWs of self-scheduled resources in Real-Time, (about half attributable to wind generation and the reminder to imports), which lowers LMPs and correspondingly loads’ costs. In response to a question, he explained that the ISO scheduled based on Day-Ahead cleared physical energy (which drives commitments) and not Day-Ahead Load Obligations. He reminded members that virtual load cleared in the Day-Ahead Market helped to improve market pricing, liquidity, and efficiency, but the ISO’s decisions as to whether supplemental commitments would be necessary were based on operational considerations. Supplemental Commitments based on Resource Adequacy Assessment (RAA) considerations had not been needed for some time. Dr. Chadalavada agreed in response to a member’s request to discuss further details concerning load obligation variables at either a Participants Committee or Markets Committee meeting.

Commenting on May NCPC, Dr. Chadalavada explained that, of the $5.6 million in total NCPC payments, $4.5 million was for first contingency payments and $1.1 million for second contingency payments. The second contingency payments arose mostly from SEMA/RI on May 19-20, and were primarily the result of outages of two large units in NEMA and SEMA. He reported that for the entire month of May, average Real-Time Load was approximately 12,327 MWh, the lowest average since May 2003.

Dr. Chadalavada reviewed slides highlighting operations on May 18, which was region's first day of summer heat and high dew points, with load exceeding 20,000 MW and numerous transmission outages and unit outages/reductions. He made special note that a 10% increase in dew points on a hot day could increase load by as much as 2,000 MWs. He summarized and reviewed the May 18 conditions that resulted from the numerous operational constraints, congestion, and divergent pricing during the day. In response to follow up questions, he provided the following details: at the time of the day's peak, there were outages totaling 8,490 MW (5,700 MW in planned outages; 2,790 MW in forced outages); and the HQ Phase II import limit dropped from 1,760 MW to 1,000 MW, caused by an equipment failure on the line which took about a day or two to correct.

He reported that, on May 18, transmission loading, with accompanying constraints, resulted in a wide-range of LMPs across the system. Notable transmission and reserve constraints affecting pricing included: interface constraints in NH, ME, and VT; North-South Interface constraints; a roughly 90-minute local Thirty-Minute Operating Reserve (TMOR) constraint in NEMA; and system replacement reserve deficiencies/constraints. As a result, not only was there significant price separation across New England due to congestion, but the average Real-Time Hub LMP during the peak hour reached $389.17 MWh (compared to a Day-Ahead Hub LMP during the peak hour of $100 MWh). He also explained that, in NEMA, Reserve Constraint Penalty Factors (RCPF) for Thirty Minute Operating Reserves (TMOR) were activated (binding), but there were sufficient resources to avoid a TMOR RCPF violation (which would have occurred had prices reached $1,000/MWh without sufficient resources available to satisfy TMOR requirements).

At a member's request, Dr. Chadalavada reported on a similar event on June 11-13, during which temperatures were in the mid-90s and dew points in the high-60s. He said load on June 12 was 23,100 MW, and increased to 24,000 MW on June 13. Those conditions resulted in an operating reserves shortage in NEMA and the need to dispatch units out-of-merit-order in order to maintain reliability in load pockets.

Dr. Chadalavada clarified in response to questions on these events that the replacement reserve constraint is only a system-wide constraint, whereas operating reserve constraints can be either or both system-wide and local. He agreed in response to another question that the upgrades on the North-South Interface in Greater Boston would have mitigated some of the constraints had those upgrades been operational.

Dr. Chadalavada concluded his presentation by warning members that, while temperatures had been below normal for May and early June, the National Weather Service was forecasting above-normal temperatures for the Northeast later in the summer.

ISO IMM ANNUAL REPORT

Dr. Jeffrey McDonald, the ISO's Internal Market Monitor (IMM), presented highlights from the IMM's 2016 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted lower wholesale power costs and uplift due to lower fuel prices in 2016, with the fuel price for natural gas-fired resources the lowest in 16 years. In response to a member's question, he noted a 34% decrease in natural gas prices and that total load decreased 2% in 2016. He explained that energy costs were the most variable of the wholesale cost components. He summarized that NCPC and reserve payments decreased by 30-35%. He noted increases of 6% in transmission upgrade costs and 15% in capacity costs (due to changes in Capacity Clearing Prices). Dr. McDonald agreed that mild winters in the past two years had had a downward impact on the price of natural gas in the region, although he acknowledged less confidence in concluding definitively what other factors might drive variations in the region's natural gas prices.

Dr. McDonald then reviewed a 5-year comparison of total wholesale costs during the first quarter (Q1) versus the remaining quarters of each year. He pointed out that almost all the variability was reflected in Q1, with a nearly direct correlation between total wholesale costs in Q1 and natural gas prices during that time.

Turning to a chart reflecting uplift payments over the past five years, he highlighted that uplift in 2016 was comparatively lower overall, roughly 60% of the amount incurred during 2015, primarily due to Market Rule changes that altered how uplift was calculated for resources committed in the Day-Ahead Energy Market.

Dr. McDonald then reviewed the impact of emission costs (particularly CO_2 credits procured through the Regional Greenhouse Gas Initiative (RGGI)) on the costs of generation. Though costs had been lower since the Clean Power Plan was put on hold, he concluded that RGGI was adding up to 15% to variable costs of impacted generation, or as much as \$3/MWh.

In response to a question on the potential impact of Massachusetts environmental regulations addressing CO_2 emission limits then under development, Dr. McDonald noted that, certainly before all the details had been ironed out, the IMM did not have a reliable estimate of how such costs might be incorporated into offers or add to the figures in the chart. However, he expressed a strong preference for a mechanism that would permit the liquid trading of emissions credits and focus on overall reductions. A member stated that concerns over MA regulations and implementation would need to be considered by the Markets Committee, particularly in light of proposed implementation of those regulations by the beginning of 2018 and the ISO's need for a process to manage impacted resources, which would have limited run hours.

Dr. McDonald then reviewed the load duration curve over the past five years, which reflected a 2% decrease in load in 2016 that was driven primarily by energy efficiency. In response to questions whether the difference in past years at the higher load levels were weather driven, Dr. McDonald stated that load had become more variable/ "peaky" over time and it was not clear what was driving the year-to-year systematic differences. He explained that 31% of load was currently met by nuclear generators and about 50% by electricity from natural gas-fired generators. Looking ahead, nuclear and coal-fired resources would be further reduced given the previously announced Brayton Point and Pilgrim retirements, with the gap created by those shutdowns to be filled primarily by natural gas-fired resources.

Focusing on imports/exports, he noted that New England continued to be a net importer of power from New York and Canada, receiving approximately 2,400 MW of electricity and 5,000 MW of import capability. He explained that most of the transactions were pre-scheduled and fixed, notwithstanding Coordinated Transaction Scheduling (CTS).

Referencing a chart, he noted that average priced supply was generally sufficient for price-driven dispatch, but during certain load and supply conditions the ISO had very little price-responsive resources to call on. In response to questions, he agreed in future reports to provide more granular analysis. He opined that downward dispatchability of price-responsive supply had increased with the Do Not Exceed Dispatch (DNE) and -$150 offer price floor Market Rule change, but it remained unclear whether new resources would participate through bidding rather than self-scheduling. He agreed to provide a more granular and frequent breakdown of those impacts.

Dr. McDonald then reviewed a chart showing how wind had increasingly helped to set Real-Time clearing prices and how virtual offers in the Day-Ahead Energy Market were helping to achieve efficient pricing convergence between Day-Ahead and Real-Time Energy Markets and helping to improve dispatch and prices in areas where pockets of wind generation were causing over-generation pockets.

He referenced a slide summarizing a relatively high degree of structural competitiveness among supply in the Day-Ahead Energy Market. He noted that, in the Real-Time Energy Market, there were some hours where there were pivotal suppliers, but he was satisfied that existing mitigation measures did and could address those circumstances.

Dr. McDonald concluded his presentation by reviewing charts reflecting that FCM had produced new entry to counter retirements, and capacity prices had declined as the system procured more entry than needed to meet Installed Capacity Requirements (ICR). He reported the Residual Supply Index (RSI) for the capacity market indicated pivotal supplier(s) exist in nearly all auctions and zones, and noted that mitigation had been applied to address any resulting economic concerns. A member cautioned that past results with respect to new entry may not be indicative of future results, given the out-of-market factors increasingly impacting development.

ISO CFO REPORT

Mr. Robert Ludlow, ISO Vice President, Chief Financial Officer (CFO) and Chief Compliance Officer, referred the Committee to the ISO 2018/19 preliminary operating and capital budget presentation included with the materials posted in advance of the meeting. He reported he had also shared this information with State Officials at the 2017 NECPUC Symposium. He identified and discussed in detail the following key components that were driving changes to the 2018/19 Budgets from 2017's budgets: increased cyber security costs (8 additional full-time equivalent (FTEs), 5 of which will be new FTEs); increases in compensation/medical and defined contribution pension plans; funding for Competitive Auctions with Subsidized Policy Resources (CASPR) studies and analyses; changes in regulatorily-mandated costs like NERC/NPCC fees; increases for FCM and other related market services; increased computer services and systems support costs; and reductions through efficiencies mitigating and reducing costs, and other cost reductions. He said that the 2018/19 Operating Budgets were projected to increase about 3.5% each year, while the 2018 Capital Budget was projected to be the same as the 2017 Capital Budget.

Focusing on the budget process, Mr. Ludlow reported that the Budget & Finance Subcommittee (Subcommittee) meeting to discuss the 2018/19 Budgets was planned for August 11. The ISO would review those Budgets with State Officials on August 15 and with the ISO Board's Audit & Finance Committee on August 17. The ISO would review feedback received from those three meetings with its full Board on September 14. Plans were for the Participants Committee to vote on the proposed budgets at its October 13 meeting, with the final ISO Board vote to be taken following the October Participants Committee meeting. Mr. Ludlow indicated that the ISO planned to file the 2018 Budgets with the FERC on October 17.

Mr. Ludlow then reported on the status of the ISO's FTR Balance of Planning Period (BoPP) implementation, as outlined in a memorandum to the Subcommittee and circulated to the Participants Committee. He explained that the ISO recognized in response to a protest filed at the FERC that it needed to make adjustments to at least one of the factors in the calculation of financial assurance margin requirements. In order to facilitate this adjustment and presentation for NEPOOL consideration, the ISO withdrew its April 20, 2017 filing on May 26. Given these circumstances, and the ISO's continuing work on the price-responsive demand (PRD) and pay-for-performance (PFP) projects, both of which had been accepted by the FERC and had to be completed/implemented by June 1, 2018, the BoPP implementation date would be delayed from the targeted September, 2017 effective date to approximately the third quarter of 2018.

A member complained about the significant delay in the implementation of FTR/BoPP auctions and long-term FTR auctions. He urged more expeditious implementation, perhaps informed by or copying how other ISOs/RTOs have implemented those markets and their associated FERC-approved financial assurance requirements.

APPROVAL OF MAY 5, 2017 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes of the May 5, 2017 teleconference meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes were unanimously approved without change.

CONSENT AGENDA

Mr. Kaslow 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, with an abstention by CSC. The CSC representative stated that CSC abstained because there was insufficient understanding of the costs and recovery mechanism for compliance with NERC standards to be implemented by Consent Agenda Item 4 (PP-11 New Procedure for Geomagnetic Disturbances).

PRD FULL INTEGRATION CONFORMING CHANGES

Mr. Alex Kuznecow referred the Committee to the materials circulated in advance of the meeting concerning a package of recommended Tariff revisions in connection with the June 1, 2018 implementation of the full integration of Demand Response Resources (DRRs) into the wholesale energy, reserves and capacity markets. He reported that portions of the PRD full integration changes had been considered separately by the Markets Committee, the Reliability

Committee, the Transmission Committee, and also by the Budget & Finance Subcommittee. The majority of the proposed changes presented to, and worked through with, the Markets Committee, culminated in a vote taken at the June 14 Markets Committee meeting. Other specific Tariff revisions were considered separately by the Budget & Finance Subcommittee at its May 12 teleconference meeting, and by the Reliability Committee at its June 20 meeting. Finally, the Transmission Committee voted on a smaller set of PRD-related changes at its June 22 meeting.

The Committee confirmed, without objection, consideration of the motions collectively. The following motions were then duly made, seconded, and unanimously approved, with an abstention noted by CSC:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1 and Section I.2.2 of the Tariff, as recommended by the ***Markets Committee*** at its June 14, 2017 meeting, and 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.

> RESOLVED, that the Participants Committee supports revisions to Tariff Sections III.1.5, III.9.5.3, III.12, and I.2.2., as recommended by the ***Reliability Committee*** at its June 20, 2017 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 Reliability Committee.

> RESOLVED, that the Participants Committee supports revisions to Tariff Sections I.3.9.3 and I.2.2., as recommended by the ***Transmission Committee***, 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 Transmission Committee.

> RESOLVED, that the Participants Committee supports revisions to Tariff Section IV.A Schedule 2 and Section I.2.2, as proposed by the ISO, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the ***Budget & Finance Subcommittee*** and the Chief Financial Officer of the ISO.

NESCOE BUDGET FRAMEWORK FOR 2018-2022

Mr. Ken Dell Orto, Budget & Finance Subcommittee Chair, referred the Committee to the materials circulated in advance of the meeting concerning NESCOE's third five-year budget framework covering years its operations for years 11-15 (or the 2018-2022 period) (the Third Budget Framework). He explained that the November 21, 2007 Memorandum of Understanding (MOU) among the ISO, NEPOOL and NESCOE required NESCOE presentation of the Third Budget Framework as it had frameworks for years 1-5 and 6-10. That MOU also required that NESCOE's annual budget not increase more than 15% in any one year or increase by more than 50% on a cumulative basis over a five-year period.

He referred to the NESCOE Third Budget Framework, which the Subcommittee considered at its May 12, 2017 meeting. He summarized that the Third Budget Framework was based on NESCOE's 2017 annual budget, with 3% annual increases for years 11-15. NESCOE, as it had during its second Budget Framework, had committed not to seek a budget increase of more than 10% in any one year or more than 30% on a cumulative basis during years 11-15, and would use any unspent funds to reduce future year's collections. He reported that the Third Budget Framework contemplated professional and administrative staffing levels consistent with those in 2016 and 2017, with some flexibility to add one additional professional if and as necessary. He stated there were no objections or concerns raised with respect to the Third Budget Framework.

The following motion was then duly made, seconded, and unanimously approved, with an abstention noted by CSC:

> RESOLVED, that the Participants Committee supports NESCOE's third five-year budget framework, for years 11 through 15 of its operations (2018-2022), as circulated for and presented at this meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report circulated and posted in advance of the meeting. He summarized at high level the post-technical conference filings with the FERC in Docket No. AD17-11 concerning the impact on markets of States' public policies, which he explained were similar to the types of issues being discussed in IMAPP.

COMMITTEE REPORTS

GIS Agreement Working Group. Mr. David Cavanaugh referred the Committee to a memorandum summarizing negotiations with respect to an Amended and Restated GIS Administration Agreement Between NEPOOL and APX, Inc. (APX) (the GIS Agreement) that had been circulated and posted with the meeting materials in advance of the meeting. He also referred to a term sheet provided to APX that formed the basis for discussions to amend and extend the GIS Agreement. He reported that the GIS Agreement Working Group had prepared two documents, one addressing technical issues and the other addressing commercial issues. Those documents were presented to APX, which then provided a proposal and supplements. The most current supplement confirmed that APX was willing to continue the current fee structure, which was a single invoice to NEPOOL based on the number of MWh tracked through the GIS, with the existing annual floor and ceiling, and a per Certificate charge for secondary transfers. He stated that an early draft term sheet was shared with the ISO for its input and reflected its input on the draft term sheet. That term sheet was then shared with APX.

Focusing on what was left to be done, he explained that the Working Group was still discussing how ongoing GIS enhancements should be incorporated into the GIS arrangements and how future changes should be managed. There would be particular focus on how to address modifications to the GIS required to reflect regulatory change, an ISO change, a rule change, or a system change.

Mr. Cavanaugh reminded the Committee that the current GIS Agreement would expire on December 31, 2017, but would automatically be extended by one year unless either NEPOOL or APX provided the other party with a termination notice by October 1, 2017. He stressed the importance of signing an agreement prior to that date, so the Working Group planned to finalize a draft agreement in time for a vote at the September 15 Participants Committee meeting.

Markets Committee. Mr. William Fowler reported that the next Markets Committee meeting was scheduled for July 11-12 at the Doubletree in Westborough, MA, with key items including CASPR and the new rules on reconfiguration and bilaterals and implementation of the demand curve associated with them. The NEPGA representative confirmed plans to discuss a settlement agreement and explanatory statement with the Markets Committee at that meeting.

Reliability Committee. Mr. Robert Stein reported that a joint summer meeting of the Reliability and Transmission Committees (RC/TC Summer Meeting) was scheduled to meet on July 18-19 at Mills Falls in Meredith, NH. Ms. Mariah Winkler reported the reservations block at Mills Falls was closed but encouraged people that were interested in attending to register on the ISO website and to contact her regarding reservations.

Transmission Committee. Mr. José Rotger also reported that, at the Joint RC/TC Summer Meeting, the Transmission Committee portion of the agenda would focus on the 2017-18 Regional Network Service (RNS) rate, with a presentation by the Transmission Owners on that rate and a 5-year RNS rate outlook.

Budget & Finance Subcommittee. Mr. Dell Orto reported that the Subcommittee was scheduled to meet on August 11 to review the ISO's proposed 2018 operating and capital budgets and NESCOE's proposed 2018 annual budget. The Subcommittee was also scheduled to meet on August 23, with the agenda, including a review of any pertinent Financial Assurance or Billing Policy issues, still being determined.

OTHER BUSINESS

Mr. Doot indicated that the next Participants Committee meeting, scheduled to be held August 4 in Boston, was likely to be re-scheduled as a teleconference meeting or cancelled given the relatively few items expected to be ready for Participants Committee discussion at that time. He urged Participants to pay close attention to notices for that meeting.

ISO EMM REPORT

Dr. David Patton, Ph.D., President, Potomac Economics, the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2016 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Reviewing highlights, he stated New England's Energy and Ancillary Services Markets performed competitively in 2016. He reported that in 2016: energy prices fell 30%, largely driven by a 34% decrease in natural gas prices, which was consistent because energy offers in competitive electricity markets should track input costs; average load was down 2% due to mild weather conditions during the year, particularly during winter; and there was very little shortage pricing due to a capacity surplus and relatively mild weather conditions. He expected more shortages to occur in the future as surplus supply shrinks, which would lead to higher revenues in the Energy and Ancillary Services Market and use of the penalty pricing regime. He noted the fluctuations in capacity prices resulting from the load/resource balance for each of the recent auctions. As with Energy and Ancillary Services, he projected that capacity prices and revenues would increase as the surplus shrinks.

Dr. Patton compared total uplift costs and uplift costs per MWh of load across the RTOs, noting the significant reductions in uplift payments in 2016 from 2015, primarily in Real-Time uplift. He observed that virtually all of the reductions were due to Market Rule changes in early 2016 that changed how NCPC payments were calculated in the Real-Time Markets. He observed that, even with the very substantial reduction in total uplift costs from 2015 to 2016, uplift costs in New England were still more than double on a per MW basis than those in NYISO and MISO.

He summarized his observations on market competitiveness, noting some market power concerns in Boston and market-wide under high-load conditions, but concluding that the markets performed competitively with very little evidence of economic and physical withholding, or other forms of market power abuses or manipulation. He reported that mitigation was infrequent in the energy markets, effective in preventing the exercise of market power, and implemented consistently with the Tariff, adding additional observations about mitigation measures for local reliability commitment. Suppliers in those instances could have the chance to increase NCPC payments above efficient levels, and the EMM recommended that the ISO consider Tariff changes to expand its authority to address this concern.

He summarized the observations in the EMM report concerning Day-Ahead and NCPC costs and reserve markets, repeating his earlier recommendation that energy and reserves be co-optimized in the Day-Ahead Market. He then responded to a series of questions. He explained that committing resources in the Day-Ahead Market for local second contingency tended to reduce congestion. Virtual trading effectively arbitraged the Real-Time congestion that occurred absent adequate Day-Ahead commitments. He noted that New England saw substantially less congestion in Real-Time as compared to NYISO and MISO. Because of the “lumpiness” of second contingency resources, there was a risk of over commitment Day-Ahead with resulting very low prices in Real-Time, and resulting NCPC uplift. Ensuring co-optimized products in the Day-Ahead Market shifts costs from uplift to market prices would achieve a desired outcome and encourage economic investments where needed. He said that he expected the Greater Boston

Upgrades and the new Footprint Power plant to reduce the need for local second contingency commitments.

He summarized the following EMM's recommendations with respect to NCPC and the reserve markets and the reasons for those recommendations: (1) change the Market Rules to co-optimize Day-Ahead Reserve and Energy Markets; and (2) eliminate the Forward Reserve Market (FRM), which was providing very little value. He clarified in response to questions why he concluded that FRM was not a desired market and his recommendation to eliminate the market rather than work to improve the signals sent by the market.

Dr. Patton referred to a chart in his presentation comparing Real-Time NCPC and virtual load and virtual supply in ISO-NE, NYISO and MISO. He noted that the percent of virtual load versus overall load was 20% of that experienced in NYISO, and 14% of MISO's experience, with similar effects for virtual supply. He strongly recommended markets with highly liquid virtual transactions, explaining the many positive impacts of such transactions on the Day-Ahead Energy Markets. He explained that poor liquidity in New England translated into poorer convergence between the Day-Ahead and Real-Time prices. He attributed New England's less desirable experiences with virtual transactions to costs allocated to those transactions, which were much greater than similar allocated costs in NYISO and MISO. Accordingly, the EMM repeated its earlier recommendation to modify the allocation of economic NCPC charges away from virtual load to be more consistent with cost-causation principles (beneficiary pays), and which he said would be more consistent with FERC's recent Notice of Proposed Rulemaking (NOPR) related to uplift allocation. He cited MISO as having the best practice in this regard and clarified why the EMM was making this recommendation. He warned that the adverse impact to the market caused by impediments to virtual trading would only increase as renewable and distributed resources increase on the system, which would will progressively degrade the performance of the Day-Ahead Energy Market.

Turning to EMM observations concerning external interface scheduling, he observed that Real-Time interchanges between ISO and NYISO were still scheduled in the unprofitable direction in 41% of intervals in 2016. He noted that CTS had produced significant cost savings, but not as large as possible, primarily because of price forecast errors. He referred the members to the EMM recommendation that the ISO reduce forecast errors by increasing the number of supply curve points that are used to model supply costs in the New England Market, particularly in steep portions of the supply curve and modify its Real-Time software to align ramp assumptions with actual ramp capacity. He said the EMM had made similar forecasting improvement recommendations to the NYISO.

Dr. Patton then summarized a chart reflecting price signals and net revenues for new and existing generation from 2015-2020. He observed that current market prices were insufficient to support new generation resources, and may not support estimated going forward costs for older steam units. He noted the EMM's conclusion that, between 2010 and 2020, 4 gigawatts (GW) of oil- and coal-fired capacity had or would retire as a result of falling prices, phase-in of PFP, phase-out of the Winter Reliability Program, and entry of state-subsidized resources.

Reviewing the portion of his presentation concerning fuel supply and demand during severe winter periods, he noted that the New England region was becoming increasingly reliant on liquefied natural gas (LNG) capacity and oil storage capacity, and that those capacities would be insufficient to meet regional needs during a significant pipeline contingency. Noting that the RTOs base resource adequacy determinations on the summer peak, the fuel supply situation at least raised the question of whether ISO-NE should have winter planning criteria distinct from the summer peak requirements and, if so, whether it should think about a seasonal capacity market. He noted in response to questions that the pipeline contingency referenced was a loss of a pipeline, which a member pointed out was extremely unlikely, although there certainly could be reductions associated with, for example, compressor failures. He also responded to a number of questions relating to the EMM's assumptions about growth in renewable and demand response resources. He clarified also in response to questions that the EMM's recommendation was to evaluate potential benefits of market changes that would complement PFP to ensure fuel security under severe winter conditions, and not that specific changes be made.

Dr. Patton then reviewed his observations on the effects of state-subsidized resources on the markets. He opined that the most cost-effective way to reduce carbon emissions was to develop a non-discriminatory, technology-neutral solution that would accommodate legitimate state policy initiatives but ideally also use the markets to achieve those initiatives. He expressed his support for CASPR generally, with the suggestion that the ISO better address the entry of new, non-subsidized resources in the market and provide broader latitude for updated retirement offers in the substitution auction. He flagged for members the relative cost per ton of carbon emission reductions achieved by various technologies, and their relative value in enhancing winter reliability, and also referred to a table summarizing the potential subsidized new entry the region might see in the next five Forward Capacity Auctions. He reported that the EMM filed comments and participated in the FERC's May 1-2 technical conference where it reviewed its concerns in all the markets it monitors. He concluded his presentation by responding to follow up questions on the EMM's recommendations.

There being no other business, the June 27, 2017 meeting ended at 4:30 p.m. to reconvene on Wednesday, June 28, 2017 at 8:30 a.m.

JUNE 28, 2017 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 28, 2017.

OPENING AND WELCOMING REMARKS

After welcoming members and guests, Mr. Kaslow referred the Committee to the Legislative Report that NEPOOL Counsel prepared and circulated at the meeting. He expressed gratitude for the strong attendance by State Officials, particularly given the dedicated focus of the region in its efforts to advance public policies of the States through the markets.

Mr. Kaslow introduced NECPUC President Martin Honigberg, Chairman of the New Hampshire Public Utilities Commission, to provide remarks on behalf of the State regulators. Chairman Honigberg thanked NEPOOL for the invitation to participate. He explained that the Commissioners welcomed the refreshing chance for discussion and open dialogue since much of their time was spent adjudicating contested matters with strict rules of engagement. He commented on his representative role with the JNC for the ISO Board selection process. He explained that NECPUC attendance at NEPOOL meetings provided a very valuable means to interact with industry participants and to hear diverse perspectives on issues confronting the region. Such insights could only help regulators as they work to address a wide range of issues including changing markets, IMAPP, siting issues, and the need for more gas infrastructure. He expressed appreciation on behalf of NECPUC to NEPOOL and the ISO for these ongoing processes.

Mr. Kaslow next introduced Secretary Matthew Beaton, Massachusetts Office of Energy and Environmental Affairs, who on behalf of Governor Charlie Baker and Lieutenant Governor Karyn Polito welcomed to Massachusetts those attending the NEPOOL Summer Meeting. He reminded members that he had attended NEPOOL's 2016 Summer Meeting and said he had been encouraged by the collaboration that had occurred since then on IMAPP. He stressed the importance of the region transmitting a positive impression to public policy makers on the work being done to find solutions. He expressed the Commonwealth's strong desire for success in the effort to integrate markets and public policies and encouraged continued progress in finding an acceptable solution.

FERC REGIONAL UPDATE

Mr. Kaslow welcomed the following FERC Staff and thanked them for attending: Mr. Daniel Nowak, Deputy Director, Office of Energy Markets Regulation, Division of Energy Regulation East; Ms. Christy Walsh, Director, Office of Energy Policy and Innovation, Division of Policy Development; Ms. Emma Nicholson, Economist, Office of Energy Policy and Innovation; and Ms. Sandra Waldstein, Director, Office of External Affairs, State, International and Public Affairs Division.

Mr. Nowak said he and his colleagues were looking forward to meeting with Sectors the next day. He cautioned members that FERC staff would not be in a positon to provide any opinions or guidance regarding the CASPR proposal. He explained that the FERC continued to operate without a quorum, with no specific schedule then identified for Senate action to confirm Commission nominees Messrs. Neil Chatterjee and Robert Powelson. He noted that Commissioner Colette Honorable was leaving the FERC on June 30, leaving acting Chairman Cheryl LaFleur as the sole Commissioner. He reviewed that, since late January the FERC had been limited on what it could approve. Staff had existing delegated authority to act on certain filings, including the authority to approve uncontested Section 205 filings and uncontested waivers, and had set some cases for hearing and settlement judge procedures where there were just issues of material fact that did not require a ruling on policy issues. In some cases, respecting statutory requirements, Staff had acted for the FERC by delegated authority to accept filings subject to refund and subject to further order. He said there is a growing backlog of rehearing requests, complaints, and merit orders related to the Section 205 filings.

Ms. Nicholson then summarized Staff's reaction to the May 1-2 Technical Conference. She thanked NEPOOL, the ISO, and the Market Participants for their participation and for helping to develop a record for the FERC to understand key challenges facing that the Northeast RTOs and ISOs. She reported that the FERC received over 700 pages of comments from over 81 entities. She said that reply comments were due on July 7 but that deadline could change in response to a motion for a one-week extension that had already been received. On FERC's price formation efforts, she reported that FERC issued final rules on Offer Caps (Order 831) and on Settlement and Shortage Pricing (Order 825). She reported on the pending NOPR to address Fast-Start pricing that was issued in December 2016, with comments received in February 2017, and the NOPR on uplift and transparency, which was issued in January 2017, with comments received in April. She also reported on the November 2016 Electric Storage NOPR, with comments received in February, and on the Large Generator Interconnection NOPR, on which comments were filed in April 2017. She concluded her remarks reporting that FERC Technical Conferences were scheduled on June 29 on natural gas index liquidity and transparency, that a conference was recently held on Bulk Power System Reliability, and that a conference was underway for discussion of increasing market and planning efficiency through improved RTO/ISO software.

ADVANCING PUBLIC POLICIES IN THE WHOLESALE MARKETS

Mr. Kaslow described the plans for the remainder of the morning, explaining that the objective was to provide the region with perspectives on the experiences in other international and national markets of more advanced efforts to further public policy goals.

International Experiences

Mr. Kaslow welcomed and introduced Mr. Michael Mehling, Deputy Director of the Center for Energy and Policy Research at the Massachusetts Institute of Technology. Mr. Mehling referred the Committee to his presentation, posted with the meeting materials, of the experiences of European countries, primarily Germany, in advancing clean energy policy goals. He explained that Germany was the 4th largest economy in the world with 82 million people, roughly $3.5 trillion in gross domestic product, and a heavy industrial base driven by manufacturing exports. Germany's size and economic structure therefore provided an interesting case study.

Mr. Mehling described the German power grid, which included four transmission system operators, one price zone, and approximately 800-850 distribution system operators. He reported that, through most of 20th century, there were about 850 generators serving load in Germany, but that number has since grown to over 2 million. Mr. Mehling said that generation remained somewhat carbon-intensive and that Germany was a net exporter of power.

He went on to refer to broader efforts for a Europe-wide integrated market, reporting that Germany was part of the Northwestern Power Pool and traded heavily with France, Belgium, Netherlands, Luxenberg, Austria, and Poland.

Mr. Mehling explained that European Union (EU) legislators and regulators had been working to liberalize and integrate European energy markets, and had issued directives to the EU members in that regard. Directives included implementation of greater price transparency, integration a market for electricity and gas, and advancing regulations related to EU environmental policy. He stated Germany's efforts reflect those of the EU.

Mr. Mehling noted that Germany's aggressive legislative targets related to reducing greenhouse gasses (GHG), increasing renewable energy and increasing energy efficiency. He identified key legislation and then reported that, in the early 2000s, a feed-in tariff was adopted that provided very attractive rates for renewable generation. As a result, Germany experienced a dramatic increase in renewable generation, with penetration growing from less than 5% of average generation to 30-35% of generation from renewables, and, for one week in June 2017, 49.4% of the country's total electricity generated by renewables.

He reported that one-half of Germany's nuclear fleet had been decommissioned since Fukushima, with the last nuclear generator scheduled to be taken offline by 2022. He reported that, while there had been a steady downward trend in Germany's carbon emissions, that trend has plateaued in recent years and Germany would not achieve its 40% GHG target (relative to 1990 levels) by 2020. He explained that the main reason for the decline in carbon reduction rates was that the European carbon market was not sending a sufficient price signal to incentivize switching from coal to gas. Furthermore, the growth of renewables had not displaced as much fossil or thermal generation as might have been expected because Germany continued to export a significant amount of energy to neighboring countries (including the Netherlands, Austria, Switzerland, the Czech Republic and, seasonally, France).

To assess any impact on reliability, Mr. Mehling referred to the System Average Interruption Duration Index (SAIDI), which measured supply service interruptions that exceed three minutes and were not due to weather alone. In Germany, the annual interruption duration average had declined from over 20 minutes to less than 12 minutes (the US annual average was 200-250 minutes on). Concerning the effect of renewable penetration on wholesale power markets, Mr. Mehling explained that renewables were displacing advanced, lower carbon-intensity thermal generation such as natural gas generation. This outcome mitigated the reduction in carbon intensity and had led to the mothballing of some advanced gas generators. Referring to wholesale power prices, he observed that prices had plateaued overall but were much more volatile with the increase in renewables.

In response to the unexpectedly quick growth in renewable energy generation on the system, much of it at the distribution level, Mr. Mehling explained that Germany had shifted to quantity planning and competitive auctions for new renewable energy capacity. He said this approach provided for greater control over the pace of renewable penetration and gave Germany more time to improve and transform grid infrastructure to deliver renewable power from the north, where there was a lot wind generation, and to the south, where much of the industrial load was located. He reported that there had been substantial congestion between the north and south, with estimated congestion costs to exceed one billion euros per year in the next few years. He said Germany did not have a robust capacity market similar to those in some US markets. He opined that Germany illustrated how markets could maintain reliability with dramatically increased renewable power, but not without significant effects on the markets and incumbent utilities.

In response to questions, Mr. Mehling confirmed that much of Germany's coal generation was from less expensive lignite coal, which partially explained why those utilities with high carbon-intensity had done well financially in recent years. Responding to a question about high retail energy prices in Germany, Mr. Mehling explained that the feed-in tariff surcharge accounts for 25-33% of Germany's retail price and that industrial customers were exempt from the tariff surcharge and other retail fees. However, while retail prices were high, the German public nevertheless supported the expansion of renewables and the decommissioning of the nuclear fleet.

California Experience Panel Discussion

Mr. Kaslow recognized Commissioner Sarah Hofmann, of the Vermont Public Utility Commission, as the moderator of a panel to discuss lessons New England could learn from California's actions to advance public policies in its wholesale power markets. She introduced the following panelists: Mr. Emilio Camacho, Chief of Staff to Commissioner David Hochschild, California (CA) Energy Commission; Mr. Mark Rothleder, Vice President, Market Quality and Renewable Integration, California ISO (CAISO); and Mr. Mark Smith, Vice President, Government and Regulatory Affairs, Calpine Corporation.

Presentation by Emilio Camacho

Referring to his PowerPoint presentation that was circulated and displayed, Mr. Camacho explained his position within the CA government, and identified CA's vision of reducing GHG emissions by 40% below 1990 levels by 2030. He listed the following five goals to achieve CA's vision: (1) implementing 50% renewable energy by 2030; (2) reducing petroleum consumption in vehicles by 50%; (3) doubling energy efficiency savings at existing buildings; (4) sequestering carbon; and (5) reducing short-lived climate pollutants. He referred the members to a graph showing progress in reducing GHG emissions since 2000, and then described some of the actions to achieve that progress. He noted that CA was meeting its objective while reducing reliance on nuclear power.

On the topic of energy efficiency in CA, he said CA enacted in 1975 its first codes designed to improve energy efficiency and has since made changes such that CA consumed half the energy per capita as did the rest of the nation. Examples were CA requirements for building and appliance efficiency, noting advancements in the efficiencies of refrigerators and televisions over time. He noted that CA adopted in 2016 standards for computers, noting that CA standards frequently become national or international standards because of the size of the CA market. He described CA efforts to use storage in improving efficiency of homes and commercial buildings.

Mr. Camacho then described research and development funding by CA aimed at helping to advance CA's vision and goals. He reported that CA planned to connect San Francisco to Los Angeles by high speed rail, 100% powered by renewables, noting the challenges in achieving that objective.

Referring to CA Renewable Portfolio Standard (RPS) goals, Mr. Camacho said CA had a goal for 20% renewables in 2013, which had been met, and had a goal for 33% renewables in 2020, which at least one utility had achieved by 2015. There had since been a goal to increase the RPS to 50% renewables by 2030, with a bill under consideration for a 100% RPS goal by 2045. He noted that CA did not count large hydro or rooftop PV solar toward meeting its RPS goals.

With respect to economic impacts, Mr. Camacho reported that the CA solar industry employed over 100,000 workers, indicating that CA projected half of its renewable energy in 2020 would be from solar resources. He explained that CA's 33 military bases contributed to the growth of renewables, with the Navy having a 50% renewable goal even before CA, and the Marines having a goal for zero fossil fuel on its bases by 2025.

Mr. Camacho concluded his presentation by stating that he expected CA's energy future to be more decentralized, technology-based, fast changing, and intelligent, with more electric vehicles, customers with solar, and enhanced two-way communication. He identified Governor Brown's disappointment with those denying climate change or refusing to give it the benefit of the doubt and address it. He summarized CA's views on climate change and his belief that those views would prevail.

Members asked questions following Mr. Camacho's presentation. On the topic of rates and charges, Mr. Camacho reported that average retail rates were $0.15/ kWh, but Mr. Smith of Calpine responded as a CA consumer that he was paying a marginal retail electricity rate of $0.40/ kWh. In response to a member's comment about the mismatch between CA wholesale and retail prices, Mr. Camacho referred to CA's efforts in response to SB 350. He explained that bill required regulators and CAISO to study barriers to achieving energy successes for disadvantaged communities. He referred to a SB 350 Barrier Study that included 13 policy recommendations.

Presentation by Mark Rothleder

Mr. Rothleder provided his perspectives given his experience at CAISO. He described his background and explained that CAISO operated 80% of the transmission grid in CA, including the service territories and systems of Southern Cal Edison, San Diego Gas & Electric, and Pacific Gas & Electric among others. He said CAISO had 30 million customers and oversaw a $9 billion market. He listed the factors driving unprecedented change in the electric industry, including the change in the Federal administration, ever-increasing renewable energy goals, efforts to reduce GHG emissions, grid modernization, consumer-owned power, transmission and distribution systems interface, gas storage challenges, community choice, regional collaboration, and fossil plant retirements.

He said that CA had peak wind production of approximately 5,000 MW and peak solar production of approximately 10,000 MW, with an additional 5,000 MW of behind-the-meter solar. He said CA would meet its 33% 2020 RPS goal ahead of schedule and needed to assess how it would handle future goals of 50% and higher. He expected growth in solar, geothermal, and wind resources. He stated the CA PUC was conducting an Integrated Resource Plan for achieving the 50% renewable goal.

Mr. Rothleder then provided some projections. He thought it likely that CA would have approximately 12,000 MW of solar facilities by 2020. He explained how that amount of penetration impacts the "duck curve" of net demand (load minus variable resources (wind and solar)). He reported that CAISO correctly predicted how net demand would impact operations but had underestimated how quickly solar would be added to the system. He said the impact had been to place a substantial premium on the need for flexible grid resources and potentially gas-fired resources. CA experience oversupply at net demand approaching 12,000-13,000 MW, requiring either that energy be exported, stored or curtailed. He explained that mid-day oversupply conditions would only last for a few hours, because as soon as the sun sets there was a steep, long ramp that was expected to get even steeper and longer as solar renewables increase. By way of example, he referred to operations on April 23, 2017, when at hour 16 about 58% of load was met by wind and solar, 65% by renewable resources, and 83% by carbon free-resources. When evening load ramped and the sun set, between hours 16 and 21, imports met about 47% of the load, gas-fired resources about 37%, and 16% of the load was met by hydro-electric facilities.

He then described and summarized the following future challenges/opportunities:

- Dispatch must be achieved to manage oversupply, minimize curtailment and realize environmental goals;
- New price patterns would provide financial incentive for responsive demand and energy storage;
- Operational performance must be maintained during periods of increased supply variability;
- Enhanced forecasting would become increasingly important to manage supply uncertainty; and
- Fault resiliency capability must be improved. CAISO was working with other reliability organizations, resources, and inverter manufactures to develop and implement short-, medium-, and long-term plans to address this.

Mr. Rothleder predicted the potential for the August 21, 2017 solar eclipse to reduce CA solar production by as much as 65% (5,600 MW) over a three-hour period, which suggested the potential need for supplemental reserves to meet load during the ramp. He estimated that CAISO might see a ramp of as much 98 MW/min as the solar eclipse passed. He concluded by suggesting CAISO needed/would experience growth in the following areas in the future: energy storage; dispatchable demand response; time-of-use rates; minimum generation; western Energy Imbalance Market expansion; regional coordination; electric vehicles; and flexible resources. He emphasized that CA was investing heavily in renewables and CAISO saw its goals as the market operator to ensure reliable and economic grid operations to maximize the benefit of the renewable resource investment.

Presentation by Mark Smith

Mr. Smith explained that his presentation, which was circulated to the members, would provide Calpine's perspective as a participant in CA's power markets and would review lessons learned for New England. He referred to substantial administrative entry (i.e., paid out-of-market), reporting that there had not been any new merchant asset enter the CA market for over 10 years. CA, instead, had produced a bilateral capacity trading pattern that had resulted in price discrimination between new resources and existing resources. He reported significant financial stress on conventional thermal resources, without a clear market-driven means to handle retirements of those resources. He acknowledged that CA had been remarkably successful in growing its renewable energy and reducing GHG emissions, but that had been at a substantial cost, with residential rates as high as $0.40/kwh ($400/MWh) for some customers. He stated New England, in its IMAPP process, was presented with a dramatic choice and encouraged swift action to improve the markets and to avoid the very costly circumstances of CA.

In comparing CA and New England, Mr. Smith stated that both regions had very aggressive GHG and RSP goals. The two regions differed, though, in where they stood with respect to solar PV market penetration. He reported CA had a centralized capacity planning mechanism that looked out 10 years and a resource adequacy requirement that was imposed on load serving entities and satisfied bilaterally rather than through a separate RTO-administered market. If CA's long-term planning suggested a future shortage, either in a very constrained local area or more generally, CA would need to issue an administrative request for proposals and bring on new capacity. For public policy reasons, CA had supported administrative entry of 15,000-20,000 MW of new renewable power.

The advancement of public policies in CA had resulted in many hours of zero or negative energy clearing prices, with premium prices not earned until late in the evening. Desirable, efficient and flexible natural gas generation turned on in the late afternoon and turned off in the early morning, which was completely opposite to the expected, historically normal dispatch cycle for those resources before the State-sponsored renewable generation was added to the grid. He explained that some of the combined-cycle units were routinely being paid uplift because they must run down to minimum load at low or negative prices. Even peaking facilities were proving uneconomic in the CA market. He summarized a number of CAISO initiatives aimed at addressing the growing operational needs. Those included a flexible ramp product, flexible forward capacity requirements (Flex RA), and changes to capacity counting rules, noting the Effective Load Carrying Capability for a new incremental solar project was close to zero, even though they might have a strong average capacity evaluation.

Mr. Smith stated that CA had been very effective in paying to get new resources online, but leaving too little revenue for existing conventional resources (e.g., paying $150-$200/kW-yr for new resources and $12-$36/kW-yr for existing resources). He referred to a chart of the financial returns based on the various revenue streams for a typical combined cycle among three CA Bay Area plants. He reported that two of the plants were not covering their fixed operating costs. He indicated he did not believe such circumstances immediately threatened reliability, but questioned how long companies could operate in those circumstances. He stated that CA was on a path to a grid comprised of renewables and Reliability Must-Run Agreements (RMRs). He said that reminded him of the Devon Power situation that sparked development of New England's Installed Capacity Market. He did not think the CA situation would create a reliability crisis but advocated for a more organized and efficient means for managing large scale retirement of conventional resources from the market.

Mr. Smith concluded by describing Calpine's experiences with four fast-start LM6000 GE turbines. Each had a capacity of 45 MW, could start in 15 minutes, met the duck curve very well, but had high fixed costs and did not receive any marginal revenue for energy. The bilateral market did not support them, in large part because load serving entities, without knowing how much load they would serve in the future, were not willing to enter into long-term contracts for those resources. The contracts Calpine had for those resources expired before the end of 2017, so Calpine had advised CAISO of its intent to remove those uneconomic resources from service if they were not needed for reliability. CAISO had determined that two of the four were needed for local reliability reasons, and those would be operated pursuant to full cost-of-service RMRs. Lessons he believed New England should take from the CA experiences included: observe and manage the enormous disconnect that can occur between wholesale rates and retail rates; acknowledge that administrative entry will clearly effect the wholesale market; and prepare for the potential growth of solar and re-emergence of RMRs.

Committee Discussion

Participants then asked questions of and discussed the presentations from the panel. An NRG representative described that company's experiences with legacy assets and new renewable projects in CA that have benefited from the administrative entry. NRG confirmed its experiences with a zealous approach to administrative entry, administrative planning, a bilateral and planning driven system that had been successful at achieving its goals but that had introduced a lot of very challenging consequences. NRG continued to advocate in CA for a transparent, visible price signal, market-based structure where there were means not only for administrative agencies to trade off one thing for another, but for the market and market actors to see those trade-offs. Its lesson for New England: beware of the unintended consequences of administrative actions that, in the end, would add expenses for customers.

A NextEra representative reported that its system also included substantial wind and solar assets in CA -- over 2,500 MW and all built under long-term contracts. She observed that, while the Power Purchase Agreement (PPA) model certainly supported development, such development could harm the competitive wholesale markets. Heavy reliance on PPAs to meet state policies would harm New England's wholesale power market. She stated there was no market anymore in CA and there were no investment signals for any new merchant build. She urged that New England avoid those consequences. New England, unlike CA, had a forward market that produced somewhat stable revenues for new investment. NextEra would continue to strive for market improvements, possibly that price carbon, that have rules that can be relied upon, that appropriately balance risk, and that allowed for financeability of new investments. She said the economics of wind and solar were improving. NextEra predicted that, by 2020, the market without subsidies could see $0.02-$0.03 for wind, $0.04 for storage, and $0.03-$0.04 for solar with the right weather conditions, wind conditions, and development costs. Given its experiences in CA and elsewhere, NextEra intended to continue its IMAPP efforts with proposals designed to allow all resources to compete in resource-neutral markets that would advance state carbon goals.

The EnerNOC representative volunteered that Company's perspective on how demand response worked in CA compared to New England. She explained that demand response in CA was more of a utility program, expanding to include an auction mechanism so utilities could meet their goals. EnerNOC noted the opportunities in the Northeast for demand response to participate more actively and directly in the wholesale markets, and indicated it was advocating for evolution in the CA markets in that direction.

The Brookfield representative reported that Brookfield owned about 400 MW in CA, mostly wind but also including one hydro facility, which had some operational challenges relating to the extreme variability in rainfall. He explained that the Brookfield wind facilities were all supported by long-term PPAs that were starting to roll off. Unless circumstances evolved to provide a more assured revenue stream following termination of the PPAs, the Company may not be willing to invest capital for the continued operation of those assets.

In response to questions concerning the CA market given very high penetration of renewable generation, Mr. Rothleder noted that CA was also confronting the policy change to reduce or eliminate once-through cooling for coastal resources. He said there were 8,000-10,000 MW of those resources that he expected would either be retired or repowered because of that regulatory change. As a result, CA risked losing flexible resources. He said CAISO had been pushing for a multi-year look-ahead perspective on resource procurement and resource adequacy and advocated for a procurement mechanism designed to achieve the right mix of resources for operating the system. He acknowledged that market changes needed to factor in the impact of renewables on market signals for procuring the right mix of resources.

On this topic Mr. Camacho noted that political changes would necessarily impact markets. In CA, there had been substantial concerns relating to environmental justice and the impact of changes in the industry on disadvantaged communities (e.g. Oxnard). Those concerns necessarily needed to be considered and responded to by regulators and CAISO.

The Committee discussed together the effects of the CA market on conventional generators. Mr. Smith said that the impacts on the energy and ancillary services markets of increased renewables penetration was known as far back as five years earlier. CA knew that revenues for conventional generation would shrink, so what was surprising was how quickly it happened.

The panel discussed what impact expansion of the fleet of electric cars would have on gross demand and the duck curve, particularly if there remained a disconnect between economic signals in the wholesale and retail markets. Mr. Rothleder stated that with 1 million electric vehicles, depending on the type of charging, demand would increase by about 700 MW to 1,000 MW, with much of that increase happening closer to the head of the duck if there were not different incentives in the market. He stated that CA needed to provide incentives to charge during the low net demand conditions (the belly of the duck), and efforts were underway to do that. Mr. Camacho added that CA currently had about 300,000 electric vehicles, may not see a million by 2020, but had been pursuing incentives to grow the electric vehicle fleet to five million. He reported that CA had a project with the Travis Air Force Base, in which the electric vehicle fleet was used to provide grid services, that might inform future activities. Referring back to discussion about retail rates, he added that CA customers’ average rate was $0.15 kW/h, but that what people cared most about was their bill which had been lower in CA because of efficiency gains.

Mr. Rothleder took the opportunity to emphasize that CAISO viewed its responsibility to operate the Day-Ahead and Real-Time markets as designed while supporting CA's policy goals as best as it could. He expressed support for changes that would incorporate GHG costs into bids and dispatch. He also noted CAISO's role in transmission planning in supporting state policy objectives and identifying transmission changes required to maintain a reliable and economically efficient system.

Following Mr. Kaslow's expression of thanks for all who participated in the morning's discussion, the June 28 session recessed at 12:00 p.m., with members reminded of the following morning's modified Sector breakout meetings the with the ISO Board, State Officials and FERC representatives.

RECOGNITION OF JOEL GORDON

During the banquet that evening, the Committee endorsed by acclimation the following resolution of appreciation for immediate-past Chairman of the Committee, Mr. Joel Gordon:

RESOLUTION OF APPRECIATION

Joel S. Gordon

WHEREAS, Mr. Joel S. Gordon, has faithfully served as the Chairman of the New England Power Pool (NEPOOL) Participants Committee from 2014 through 2016, following five years as the Supplier Sector Vice-Chair and distinguished service for many years prior as a NEPOOL representative and leader; and

WHEREAS, during his tenure, Joel was dedicated to increasing the visibility, reputation and effectiveness of NEPOOL for its members; and

WHEREAS, Joel successfully brought together markets and state policy interests through the NEPOOL IMAPP stakeholder process and established stronger relationships and open dialogue between NEPOOL, NECPUC, NESCOE and the states; and

WHEREAS, Joel has consistently driven NEPOOL in its mission "to create and sustain open, non-discriminatory, competitive, unbundled, markets for energy, capacity and ancillary services (including operating reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participate to receive compensation through the market for a service it provides, in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets"; and

WHEREAS, Joel significantly increased NEPOOL's presence in the business priority planning process and secured NEPOOL-directed priorities in energy market pricing, capacity market enhancements, economic planning and improvements to support new entry; and

WHEREAS, under Joel's leadership, NEPOOL uniquely expressed its own proposed market rule changes twice at the FERC under Section 205 of the EPA using the Jump Ball provisions; and

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Joel for his service as its Chairman over the past 3 years and for his leadership and dedication to NEPOOL as THE stakeholder process for wholesale electric market rules in New England.

JUNE 29, 2017 SESSION

The June 29 session of the Summer Meeting convened at 8:00 a.m., in modified Sector breakout meetings with the ISO Board, State Officials, and FERC representatives, which continued until 12:15 p.m. With no further Committee business thereafter, the Summer Meeting adjourned.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN THE PARTICIPANTS COMMITTEE JUNE 27-29, 2017 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary Smith
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
AVANGRID (CMP/UI)	Transmission			Alan Trotta, Paul Dumais
Belmont Municipal Light Department	Publicly Owned		Tim Hebert	
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Tim Hebert
Brookfield Energy Marketing	Supplier	Aleks Mitreski	Nicolas Bosse	
Calpine Energy Services, L.P.	Supplier	John Flumerfelt	Brett Kruse	Bill Fowler
Chester Municipal Electric Light Department	Publicly Owned		Tim Hebert	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Citigroup Energy Inc.	Supplier	Barry Trayers		
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Tim Hebert	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned	Brian Forshaw		
Connecticut, State of, Office of Consumer Counsel	End User	Elin Katz		Dave Thompson
Conservation Law Foundation (CLF)	End User	Jerry Elmer		
CPV Towantic, LLC	Generation	Daniel Pierpont		
Cross-Sound Cable (CSC)	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned		Tim Hebert	
Direct Energy Business, LLC	Supplier	Ron Carrier	Marji Philips	Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Jim Davis	Michael Batta	
DTE Energy Trading, Inc. (DTE)	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Maine	Transmission		Sandi Hennequin	Lisa Martin
EnerNOC, Inc.	AR	Sarah Griffiths		Doug Hurley
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
Essential Power, LLC	Generation	Lisa Krueger	Bill Fowler	
Eversource Energy	Transmission	James Daly	Cal Bowie	Vandan Divatia
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
FirstLight Power Resources Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	Nancy Chafetz		
Generation Group Member	Generation			Bob Stein Susan Muller (tel)
Georgetown Municipal Light Department	Publicly Owned		Tim Hebert	
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Tim Hebert	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	
Harvard Dedicated Energy Limited	End User	Mary Smith		Paul Peterson Doug Hurley
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		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Industrial Energy Consumer Group (IECG)	End User	Don Sipe		
Invenergy Energy Management LLC	Generation	Alex Ma		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
THE PARTICIPANTS COMMITTEE
JUNE 27-29, 2017 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Just Energy (U.S.) Corp.	Supplier	Gretchen Fuhr		
Long Island Lighting Company (LIPA)	Supplier	Bill Killgoar		
Littleton (MA) Electric Light & Water Department	Publicly Owned		Tim Hebert	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate Office	End User		Barry Hobbins	
Maine Skiing, Inc.	End User	Don Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
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	Brian Thomson		Brian Forshaw
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Tim Herbert	
Middleborough Gas and Electric Department	Publicly Owned		Brian Thomson	
Middleton Municipal Electric Department	Publicly Owned		Tim Hebert	
National Grid	Transmission	Tim Brennan	Tim Martin	
New Brunswick Energy Marketing Corp.	Supplier	Rick McGivney		
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Chris Sherman	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh	Pete Fuller	
Pascoag Utility District	Publicly Owned		Tim Hebert	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Plant	Publicly Owned		Brian Thomson	
PowerOptions	End User	Cynthia Arcate		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
Repsol Energy North America Company	Gas Industry Participant			Nancy Chafetz
Rowley Municipal Lighting Plant	Publicly Owned		Tim Hebert	
Russell Municipal Light Dept	Publicly Owned		Brian Thomson	
Saint Anselm College	End User	Gus Fromuth		
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
Shipyard Brewing LLC	End User	Gus Fromuth	Stacy Dimou (tel)	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Tim Hebert	
Sun Edison (Stetson Holdings)	AR	John Keene		Bob Stein
Tangent Energy Solutions	AR	Brad Swalwell (tel)		
Taunton Municipal Light Department	Publicly Owned		Tim Hebert	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Texas Retail, LLC	Supplier	Chris Hendrix		
The Energy Consortium (TEC)	End User		Mary Smith	Paul Peterson Doug Hurley Fred Plett
Union of Concerned Scientists (UCS)	End User		Francis Pullaro	

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MEMBERS AND ALTERNATES PARTICIPATING IN THE PARTICIPANTS COMMITTEE JUNE 27-29, 2017 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission	Frank Ettori		
Vermont Energy Investment Corporation (VEIC)	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Tim Hebert	
Wellesley Municipal Light Plant	Publicly Owned		Tim Hebert	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Light Department	Publicly Owned		Tim Hebert	
Wheelabrator North Andover Inc.	AR	Bill Fowler		
Z-TECH, LLC	End User		Gus Fromuth	